AECOM

Next Generation Carbon Capture Technology

Technoeconomic Analysis
Work Package 6

Department for Business, Energy and Industrial Strategy

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1. Acknowledgements

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2. Executive Summary

AECOM was appointed by BEIS to conduct a review and technoeconomic analysis of next generation carbon capture technologies for application in the industrial, waste and power sectors. As well as technoeconomic assessment, the report includes appraisal of the demonstration status, opportunities, and challenges of the various technologies examined. For some of the technologies the relative merits of applying them to different industrial emitters have been investigated. The work is intended to inform the UK Government and provide guidance to industries that may develop carbon capture projects as part of their decarbonisation strategy.

Being a leader in the development of next generation capture technologies should aid decarbonisation of UK industry, be valuable for the UK economy, and benefit energy intensive industries in the UK. However, realistic expectations are required for commercial deployment timescales given the challenges associated with carbon capture and the current development status of next generation technologies. The price paid by industry for emitting CO_2 in the coming years will be a key factor influencing the speed and scale of carbon capture deployment.

Priorities to support development and deployment of the next generation technologies analysed should be the demonstration of key components under representative conditions and the construction of intermediate scale demonstration plants.

Outputs from the study are contained in three reports.

- Next Generation Carbon Capture Technology - Technoeconomic Analysis (this report)
- Next Generation Carbon Capture Technology - Technology Review (Annex 1 to this report)
- Mobile De-risking Plant (Annex 2 to this report)

Next Generation Carbon Capture Technology - Technoeconomic Analysis

The technoeconomic analysis conducted compares next generation capture technologies against benchmarks based on amine solvent capture technology. Amine solvents were used as the benchmark as they are the most established capture technology.

Scenarios have been developed for utility scale gas power generation, energy from waste (EfW) and cement manufacture applications. These industries are likely candidates for capture technology application. In addition, they have a range of flue gas conditions and integration challenges that are representative of a wider range of industries. The results obtained should be of use to a wider range of industrial emitters. For example, the application of capture to EfW will have similarities to the application of capture to biomass power generation.

Methodology

For each scenario a description of the capture technology is provided along with information on current demonstration status, technical challenges, development opportunities, capital and operational costs, levelised cost of capture (LCOC), impact of capture on product price and a summary of assumptions and uncertainties. Full details of the methodology used are provided in Appendix B.

Limitations of Analysis

The study analyses capture technologies and process alterations that make capture easier by creating a more concentrated stream of CO_2. In every scenario, equipment is included to allow a pipeline grade CO_2 product to be produced. However, the transport and storage of CO_2 is not included in this assignment. Alternative decarbonisation options are also not considered. In some cases, alternative decarbonisation options such as demand reduction, fuel switching, electrification or efficiency measures may offer simpler, more cost-effective opportunities for decarbonisation.

The study has examined several capture technologies applied to different industries, allowing comparisons between technologies and industries to be made. However, the time and budget available for the study has limited the level of project definition and the engineering time available for each scenario. The approach has been to review process information provided by equipment providers, apply corrections for input and output conditions and to adjust the data, and or highlight uncertainties, where considered appropriate.

Availability of reliable performance data is a challenge for any emerging technology. Information on important elements of plant performance may not exist if representative testing is yet to be conducted. Where data has been unavailable, professional judgement has been used to estimate the necessary information. The limitations of this approach must be acknowledged in interpretation of the results.

This study makes no attempt to predict the influence that ongoing external events may have on future market conditions relating to the work. Current concerns about energy costs and security may make carbon capture appear less attractive. However, it is important that a long-term view is taken and the potential value of carbon capture as a decarbonisation tool is understood.

Deployment of Carbon Capture

Carbon capture and storage is expected to play an important role in decarbonising the future energy system. It should also unlock opportunities in the manufacture of low carbon products for domestic and international use.

It is reasonable to assume some level of carbon capture deployment in the modelling of national decarbonisation strategies. However, it is important that the uncertainties and challenges associated with the technology are understood when making judgements in relation to costs, timescales, and the level of reliance to be placed on emerging technology. An over reliance on an emerging technology could increase the risk of failing to meet carbon reduction targets and may negatively impact public perception of a valuable technology.

Readiness of Next Generation Technologies

The term ‘next generation’ has been used to describe a variety of developing capture technologies. However, it should be noted that in the applications considered there is no established current generation of capture technology.

Pilot facilities have been constructed for all technologies analysed. However, none of them, except for the advanced amine systems, have been built with a scale larger than c.75 tpd of CO_2 capture. Furthermore, many of the pilot facilities have either only operated for a short period, not operated continuously, or have not provided an indication of how long equipment operated for. The base year of this technoeconomic analysis is 2025, and the capture scales investigated range from approximately 1,000 tpd for EfW to around 6,500 tpd for gas fired power generation. Due to the development status of the technologies being analysed, many of them are not realistically expected be ready for deployment at the modelled scales by 2025, or for some time after.

Current priorities for these technologies should be the testing of key components under representative operational conditions and the construction of intermediate scale demonstration plants.

Technoeconomic Analysis Results

LCOC results from the technoeconomic analysis are presented in Figure 1.

Figure 1. LCOC breakdown for all scenarios

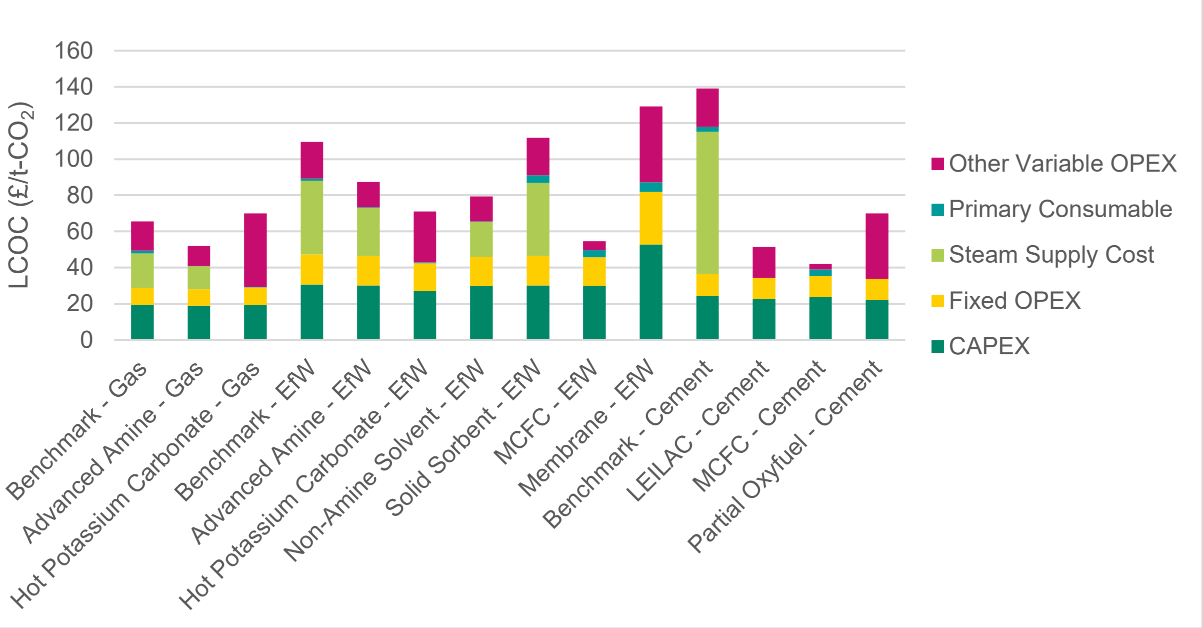


Figure 1 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% or greater for all scenarios other than, Hot Potassium Carbonate – Gas (90%), LEILAC – Cement (60%), Membrane – EfW (60%) and Partial oxyfuel – Cement (60%). Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
3. Capture plant scale and the assumed cost of thermal energy vary between the industry sectors analysed.
4. All scenarios produce pipeline grade CO_2. For the molten carbonate fuel cells (MCFCs) and membrane scenarios CO_2 is produced in liquid phase.
5. The MCFC scenarios also consume natural gas and generate electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The 'Other variable OPEX' segment in the MCFC scenarios include both a natural gas cost and a negative operating cost resulting from electricity export.
6. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the EfW and cement sectors, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the core process, and hence LCOC is reduced commensurately.
7. The Low Emissions Intensity Lime and Cement (LEILAC) and partial oxyfuel cement scenarios are process alterations that aid capture, rather than standalone capture technologies. Impacts on the cement manufacturing process may not be reflected in the LCOC values. In new build projects capital cost reductions would be possible for these technologies as conventional equipment is replaced.
8. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

In addition to LCOC, impact on product cost results have been derived for each scenario. In contrast to LCOC, the impact on product cost calculation includes the cost of residual CO_2 emissions to the atmosphere. The BEIS Green Book 2021 central values for CO_2 emission prices have been used. These are intended to represent a cost that a UK industrial site may need to pay when transitioning to a net zero business environment. They do not necessarily represent the current EU emissions trading scheme and are not a prediction of future emissions trading prices.

With the assumed CO_2 emission prices, the impact on product cost is higher in technology scenarios with lower capture levels. This is due to the relatively high cost of emitting residual CO_2 to the atmosphere. If CO_2 emission prices were lower, then a solution offering an attractive LCOC, but with a lower capture level, may give a lower cost of product. If the cost of emitting CO_2 to the atmosphere is low, or zero as is currently the case in many industries, then carbon capture will not be economically attractive. The price paid by industry for residual CO_2 emissions will be a key factor in determining the timescales and level of deployment of capture technology.

If high capture levels are achieved, the addition of capture means that both the EfW and cement scenarios have the potential to operate with net negative emissions of CO_2. For EfW plants this is due to the presence of carbon of biogenic origin in the feedstock. Cement plants may also use waste containing biogenic carbon as a fuel, and the cement absorbs CO_2 during its lifetime. There are currently few technologies with the potential to operate with net negative emissions of CO_2, and it needs to be acknowledged as an additional service being provided.

All results in this study are intended to provide a high-level comparison of different next generation capture technology options based on available information. If constructed actual performance may vary. For the avoidance of doubt, the results must not be used for making investment decisions and are not a warranted or guaranteed level of performance.

Next Steps

Actions have been identified for government to support the development of carbon capture, including next generation technologies.

1. Continue to encourage industries to consider developing capture projects.
2. Continue to take action on related issues such as development of associated regulations, permitting frameworks, fiscal incentive schemes and transport and storage infrastructure.
3. Encourage the development of carbon capture projects in industries where it is relatively low cost and technically simple to capture the CO_2. These industries include brewing and distilling, biomethane upgrading and industrial hydrogen production. CO_2 separation is an integral part of these processes and capture already takes place at some sites to serve the domestic market for CO_2. However, much of the available CO_2 is vented to atmosphere due to the limited size of the market and the lack of CO_2 transport and storage infrastructure. In the near-term, increased capture from some of these industries could diversify supply to the existing domestic CO_2 market. Once the appropriate infrastructure has been developed these industries have the potential to develop low-cost CO_2 to storage projects.
4. De-risk technology through supporting the long-term testing of key components, such as solvents, sorbents, fuel cells and membrane materials under representative conditions. This could be achieved with relatively small-scale testing rigs (in the order of 10 tpd) located adjacent to industrial emitters.
5. Support the construction of mid-scale demonstration facilities (in the order of 100 tpd) to validate other aspects of plant performance including constructability, capital cost, reliability, and energy requirements.

An appropriate size for new demonstration facilities will depend on the scale, configuration and success of existing projects using the technology being developed. A balance is required between the desire to achieve rapid scale-up and the need to manage technical risk. Premature large-scale deployment increases the risk of failing projects and is likely to slow innovation and development in the sector.

To encourage innovation there is value in developing a range of capture technologies. The inclusion of higher-risk technologies can be justified if they have worthwhile associated benefits. A portfolio of innovative technologies will also benefit from parallel development of lower risk options to support market development and associated infrastructure. A modest project that is constructed and operates in line with expectations will be of greater value than a more ambitious project that suffers overruns or fails to operate reliably.

Some important sources of finance are only likely to consider investment if there are multiple existing plants that can demonstrate years of successful operation with availability that matches financial model assumptions. This will impact the type of business model that can be used for the development of next generation technologies.

Next Generation Carbon Capture Technology – Technology Review (Annex 1)

The Review of Next Generation Carbon Capture Technology report covers the following areas.

- **Established carbon capture applications** - The low-cost CO_2 capture opportunities available in industries such as brewing and distilling, biogas upgrading, and hydrogen production for use in the chemicals industry.
- **Cost reduction through commercial deployment** - Understanding the value of, and difference between, technology development through incremental improvements to existing concepts and through the development of new concepts.
- **Deployment risk optimisation -** Promoting successful innovation through understanding risk and the limitations of excessively high, or low, risk innovation strategies. Highlighting the vital difference between having a demonstration plant and having demonstrated successful operation.

- **Technology categorisation -** Explanation of the categorisation system used in the report and the challenges of categorising multiple, varied technologies, with limited information.
- **Demonstration stage technologies** - The next generation technologies most likely to be deployable at around 1000 tpd scale by 2030 are mostly amine based solvent systems. These technologies can be developed by a range of incremental improvements.
- **Development stage technologies -** Technologies that are considered more likely to be deployable at around 1000 tpd scale by 2035, or later, have been classified as development stage technologies. These technologies have potential advantages over more developed technologies, but it remains to be proven whether technical issues and challenges associated with scale-up can be overcome.
- **Research stage technologies -** Technologies or components at an earlier stage of development, mostly having only been tested at lab scale.
- **Opportunities and Barriers -** An overview of opportunities and barriers to carbon capture, including a section on industry specific opportunities and barriers.
- **Industry Engagement Workshop** - Results are presented from an industry engagement workshop held on 30 September 2021 in collaboration with the UK Carbon Capture and Storage Research Centre (UK CCSRC), Jon Gibbins of the University of Sheffield and BEIS.

Mobile De-risking Plant (Annex 2)

The need for, and value of, long duration representative testing of key components of capture technologies has been a recurring theme throughout this assignment. Such components include solvents, sorbents, fuel cells and membranes.

A case study was completed for a mobile solvent-based carbon capture plant with a nominal capture capacity of nine tonnes per day of CO_2 captured from an EfW plant. With minor modifications a unit of this type could also process flue gas from gas power generation or other industrial processes.

The estimated budget for the unit is £4 million and it has an outline schedule of approximately 20 months from beginning of front-end engineering design (FEED) through to operation. Units of this kind would be valuable for understanding component performance, de-risking carbon capture deployment and developing site-specific process optimisations.

3. Introduction

AECOM has been appointed by BEIS to conduct a review and technoeconomic analysis of next generation carbon capture technologies for industry, waste and power applications. The technology review is contained in the *Review of Next Generation Capture Technologies* report published alongside this document. This report presents the methodology and outputs of the technoeconomic analysis.

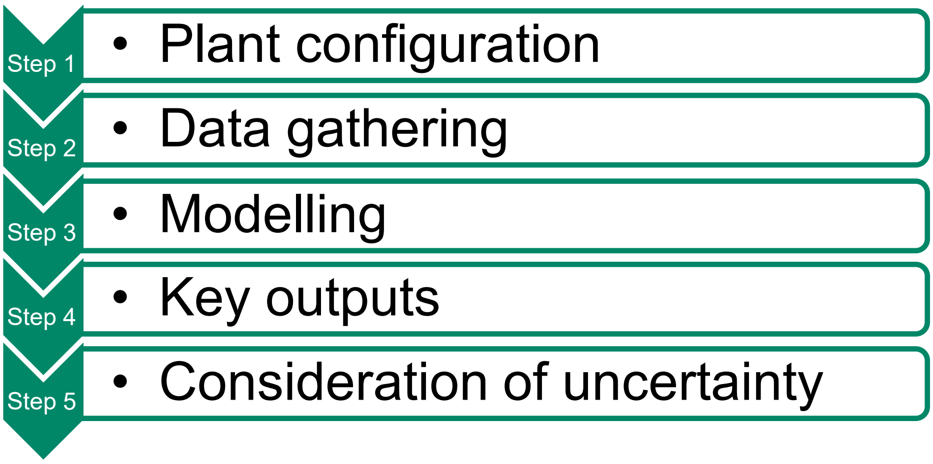
The technoeconomic analysis compares next generation carbon capture technologies against benchmarks based on amine solvent packed bed absorber capture plants. This is considered to be the most established post combustion capture technology at the scale considered in this study.

Benchmark and next generation technology scenarios have been developed for a variety of industry sectors including gas power generation, Energy from Waste (EfW) and cement manufacture. These industries were selected as they are likely candidates for capture technology applications in the future. Furthermore, these sectors have a range of flue gas conditions and integration challenges that will be comparable to other industries. The results obtained will therefore be of use to a wider range of industrial emitters.

3.1 Methodology

Figure 2 shows a diagrammatic representation of the main steps in the technoeconomic analysis methodology.

Figure 2. Technoeconomic Analysis Steps



For each benchmark and next generation technology scenario, the following information has been provided

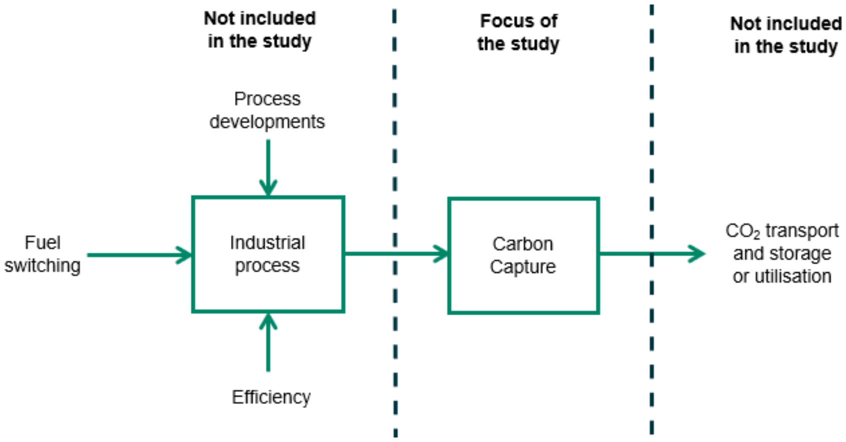
- A description of the scenario including technology demonstration status and development opportunities
- A summary of estimated capital and operational costs
- Key study outputs, including levelised cost of capture (LCOC) and impact of capture on product price
- A summary of assumptions and uncertainties

Appendix B contains a full explanation of the methodology used.

3.1.1 Limitations of the Analysis

Figure 3 illustrates the scope of the study with respect to the elements of the carbon capture and storage chain considered. Transport and storage of CO_2 has not been considered in this analysis, and so the cost figures presented do not include costs for transportation, injection and long-term storage of the captured CO_2. Similarly, it does not include the industrial process that generates the CO_2, except where this is an integral part of the capture technology.

Figure 3. Scope of the study



Alternative decarbonisation options such as demand reduction, fuel switching, electrification, alternative process options, heat exports or efficiency measures have not been included in the study. In some cases, alternative decarbonisation options may offer a simpler, more cost-effective opportunities for decarbonisation than the application of carbon capture.

The study provides a high-level overview of several next generation technology scenarios. Time and resource limitations restrict the level of project definition for each scenario. Front end engineering designs of the different processes have not been conducted. The approach of the study has been to review process information provided by licensors and equipment providers, apply corrections for input and output conditions and to adjust the data, and or highlight uncertainties, where considered appropriate. While all data has been reviewed by AECOM, the use of licensor or provider data in relation to emerging technologies has the potential to introduce an optimism bias.

If front end engineering design work were to be conducted for the selected technologies, the level of uncertainty in the results obtained would remain high due to the limited development status of many of the technologies. Many of the technologies analysed are not sufficiently developed for accurate cost or performance data to be available for the scales of projects being analysed in the study. Where information is available, some owners have legitimate commercial reasons for not sharing it in the public domain.

Where data has been unavailable, professional judgement has been used to estimate the necessary information. The limitations of this approach must be acknowledged in interpretation of the results. The differences in results obtained between scenarios may be outweighed by the uncertainties associated with the analysis. All results presented must be considered in conjunction with information provided on demonstration status, opportunities, challenges, and assumptions.

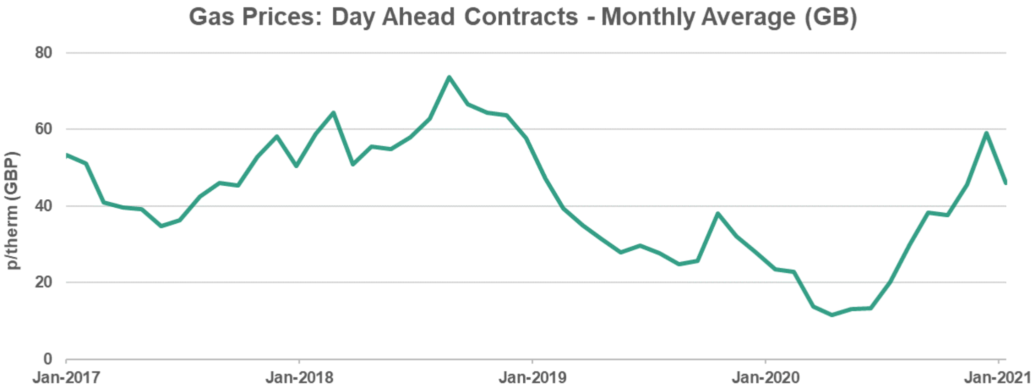
There are other promising capture technologies that have not been included in this study.

3.1.2 Changing Market Conditions

Market conditions in the industry sectors included in this analysis, and in the wider energy sector, are continually fluctuating and volatile. At the time of conducting this work, the influences of the Covid-19 pandemic, the UK's exit from the European Union and the conflict in Ukraine all have potential to create material changes in UK market conditions that could impact results and conclusions from this study.

Figure 4 illustrates the variability in wholesale gas prices prior to the conflict in Ukraine, to demonstrate the significant long term variability of gas prices due to fluctuating global economic and political influences prior to this specific event.

Figure 4. Gas price information from Ofgem



This study makes no attempt to predict the influence that ongoing external events may have on energy security or future market conditions relating to the work.

Changing market conditions will undoubtedly create challenges for industries and, along with the government support models for driving industrial decarbonisation, will influence the selection of approach and technologies adopted. Current concerns about energy costs and security may make carbon capture appear less attractive. However, it is important that a long-term view is taken and the potential contribution of carbon capture to support decarbonisation of power and industry is understood. Without significant action the impacts of climate change will become increasingly severe.

3.2 Deployment of Carbon Capture

Carbon capture and storage is expected to play an important role in decarbonising the future energy system. It could also unlock opportunities in the manufacture of low carbon products for domestic use and international export. However, it is important to understand the uncertainties and challenges associated with deployment of the technology so that informed judgements can be made in relation to costs and timescales. Carbon capture and storage has been studied and proposed as a decarbonisation tool for decades. To date, there are very few large-scale operational projects globally, and none in the UK.

Figure 5 shows the world's largest post combustion CCS plant based at the Petra Nova coal fired power station in Texas, USA. The plant had a capacity of 4,700 tpd of CO_2 capture and operated between 2016 and 2020. The facility received US government funding and generated income from the use of captured CO_2 in enhanced oil recovery.

Figure 5. Petra Nova Carbon Capture Plant

Image courtesy of www.nrg.com

The results of this analysis, and any other analysis of carbon capture technology, rely on the successful resolution of a range of technical, economic and political challenges. Issues include the currently low cost of emitting CO_2 to the atmosphere, the complexities of cross border carbon tariffs, the lack of CO_2 transport and storage infrastructure, etc. Opportunities and barriers for carbon capture are further detailed in the *Review of Next Generation Carbon Capture Technologies* report.

It is reasonable to assume some level of carbon capture deployment in the modelling of national decarbonisation strategies. However, it is essential that the uncertainties associated with the technology are understood when deciding the level of reliance to be placed on carbon capture, relative to other decarbonisation options. An over reliance on an emerging technology could increase the risk of failing to meet carbon reduction targets and may negatively impact public perception of a valuable technology. Public perception is important in relation to the development of any technology.

The addition of capture technology adds to the cost of products and services. However, if high capture levels are achieved the addition of capture means that both the EfW and cement scenarios have the potential to operate with net negative emissions of CO_2. For EfW plants this is due to the presence of carbon of biogenic origin in the feedstock. Cement plants may also use waste containing biogenic carbon as a fuel and the cement absorbs CO_2 during its lifetime.

There are currently few technologies with the potential to operate with net negative emissions of CO_2, and it needs to be acknowledged as an additional service being offered by the plants. For capture technologies to be developed the value associated with the provision of low and or negative carbon products and services needs to be understood and valued.

3.3 Readiness of Next Generation Technologies

Being a leader in the development of next generation capture technologies would be valuable for the UK economy, and for industries based in the UK. This study provides indications of performance and highlights opportunities and areas of uncertainty for next generation capture technologies. The work is intended to provide information to industries that may develop carbon capture projects, and may consider the use of next generation technologies, as part of their decarbonisation strategy.

The term ‘Next generation’ has been used to describe a variety of technologies that are being developed for use in carbon capture applications. However, it is noted that there are currently few large-scale post combustion capture projects in operation, and the application to different sectors is also limited. In most applications, there is not an established current generation of capture technology.

Pilot facilities have been constructed for all technologies analysed, and valuable lessons will have been learned through development of these projects. However, none of them, except for the advanced amine systems, have been built with a scale larger than c.75 tpd. This is less than one tenth of the scale of the 1,000 tpd EfW scenarios modelled and smaller still in relation to the cement or gas fired power generation scenarios. Furthermore, many of the pilot facilities have either only operated for a short period, not operated continuously, or have not provided an indication of how long equipment operated for. This needs to be considered in relation to the results obtained and realistic expectations are required in relation to the timescales for deployment of next generation capture technologies.

The base year of this technoeconomic analysis is 2025, and the capture scales investigated range from approximately 1,000 tpd for EfW to around 6,500 tpd for gas fired power generation. Due to the development status of the technologies being analysed, many of them are not realistically expected be ready for deployment at the modelled scales by 2025, or for some time after. The current priorities for these technologies should be the demonstration of key components under representative operational conditions and the construction of intermediate scale demonstration plants. Figure 6 shows a 1 tpd solvent pilot scale carbon capture plant at the Translational Energy Research Centre (TERC), University of Sheffield. This type of facility can be used for testing solvents and other components.

Figure 6. Pilot scale amine capture plant, Translational Energy Research Centre (TERC), University of Sheffield (www.terc.ac.uk)

Image used with permission of UoS

Test conditions for key components of a capture technology must reflect the conditions that the component will be exposed to in its intended application. This will include input flue gas composition, plant configuration, operating temperatures and pressures and reclaiming equipment for solvents and sorbents. If test conditions are not representative of the intended application, then results obtained could be misleading, for example if solvent management costs were based on the degradation of fresh solvent rather than the performance of solvent that had been allowed to reach steady state conditions with representative reclaiming equipment.

3.4 Next steps

Actions have been identified for government to support the development of carbon capture, including next generation technologies. These actions are outlined below.

1. Continue to encourage industries to consider carbon capture projects as part of their portfolio of decarbonisation measures.
2. Continue to act on issues that relate to carbon capture, usage and storage, but not directly to the capture technology. These issues will include development of associated regulations, permitting frameworks, guidance, fiscal incentive schemes and transport and storage infrastructure.
3. Encourage the development of carbon capture projects in industries where it is relatively low cost and technically simple to capture the CO_2. These industries include brewing and distilling, biomethane upgrading and industrial hydrogen production. CO_2 separation is an integral part of these processes and capture already takes place at some sites to serve the domestic market for CO_2. However, much of the available CO_2 is vented to atmosphere due to the limited size of the market and the lack of CO_2 transport and storage infrastructure. In the near-term, increased capture from some of these industries could diversify supply to the existing domestic CO_2 market. Once the appropriate infrastructure has been developed these industries have the potential to develop low-cost CO_2 to storage projects.
4. De-risk technology through supporting the long-term testing of key components, such as solvents, sorbents, fuel cells and membrane materials under representative conditions. Performance of key components of the capture technologies is a source of uncertainty in relation to technology performance, and long-term testing would provide data to reduce levels of performance uncertainty.

   What constitutes representative conditions will be technology specific but is likely to include input flue gas composition, plant configuration, operating temperatures and pressures and regeneration equipment for solvents and sorbents. This could be achieved with relatively small-scale testing rigs (in the order of 10 tpd) located adjacent to industrial emitters. The requirements of a mobile de-risking plant for solvents have been outlined in a separate report produced as part of this assignment.

5. Support the construction of mid-scale demonstration facilities (in the order of 100 tpd) can then be used to validate other aspects of plant performance including constructability, capital cost, reliability, and the performance of heat integration systems. Engineering studies are an essential tool for making performance predictions for new plants. However, all studies have their limitations and, particularly for new technologies, levels of uncertainty can remain high prior to the construction and operation of demonstration facilities.

The length of time that demonstration facilities are required to operate for will vary between sites and technologies. Some aspects of performance, such as plant energy requirements on a fresh solvent, could be validated by relatively short duration operational tests (a few hours). Other aspects of performance, such as availability and / or long-term maintenance requirements are best demonstrated over a period of years. Key measures of performance will vary between initial conditions, with a fresh solvent, and long-term performance with a solvent inventory that has aged and is being managed to control impurity levels.

Some important sources of finance are only likely to consider investment if there are multiple existing plants that can demonstrate a number of years of operation with performance and availability demonstrated to be in line with financial model assumptions. This will impact the range of sources of finance that can be used for the development of next generation capture technologies.

An appropriate scale for new demonstration facilities will depend on the scale, configuration and success of existing projects using the technology being developed. A balance is required between the desire to achieve rapid scale-up and the need to manage technical risk and validate performance predictions prior to making more substantial investments. Premature large-scale deployment of technologies that have not reached a sufficient state of development increases the risk of failing projects. This could damage the credibility of the carbon capture industry, slow the development of the technology and lead to large financial losses for investors and lenders.

For the UK, there would be value in developing a range of capture technologies. The inclusion of higher-risk technologies can be justified if they have worthwhile associated benefits. However, a portfolio of innovative technologies will also benefit from parallel development of lower risk options to support the development of a market and associated infrastructure. In the development of CCUS as a new industry, a modest project that is constructed and operates in line with expectations will be of greater value than a more ambitious project that suffers cost overruns or fails to operate reliably.

Figure 7 shows an intermediate scale (110 tpd) Pentair Union plant installed by Tata Chemicals Europe.

Figure 7. Demonstration plant developed by Tata Chemicals Europe

Image used with the permission of Tata Chemicals Europe

4. Summary of Results

This section presents the results from the benchmark amine capture cases on gas fired power generation, EfW and cement manufacture. The next generation capture technology scenarios are then compared with the benchmarks for each industry sector.

Figure 8 shows the LCOC for all benchmarks and scenarios. The LCOC values in all charts in this report relate to the cost of capture only. Costs for residual emissions and CO_2 transportation and storage are not included.

Figure 8. LCOC breakdown for all scenarios

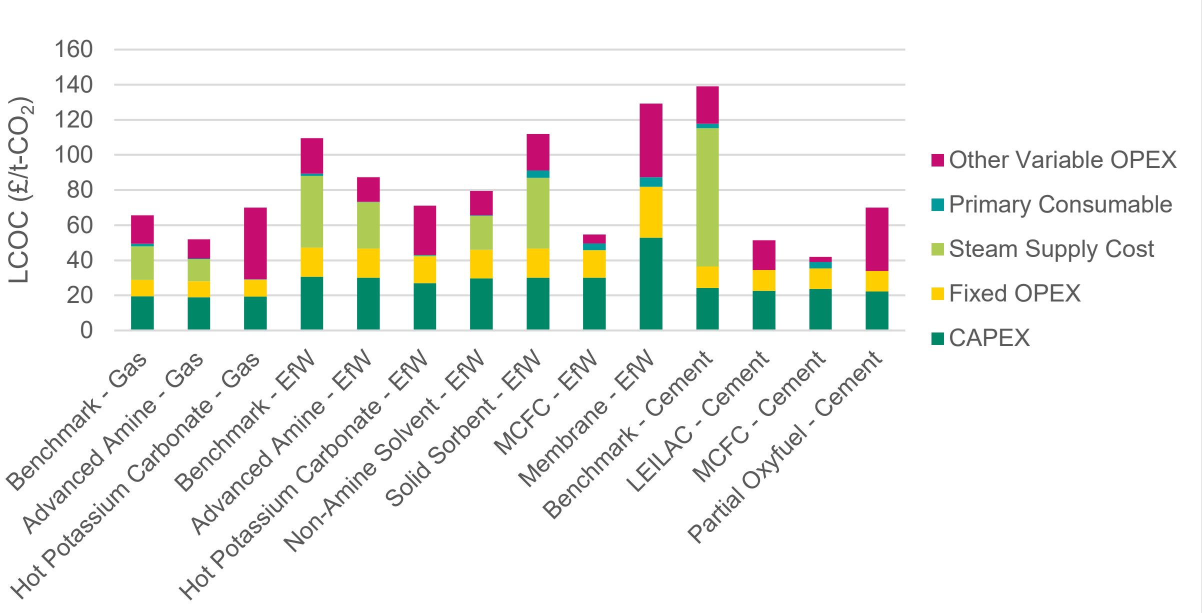


Figure 8 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% or greater for all scenarios other than, Hot Potassium Carbonate – Gas (90%), LEILAC – Cement (60%), Membrane – EfW (60%) and Partial oxyfuel – Cement (60%). Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
3. Capture plant scale and the assumed cost of thermal energy vary between the industry sectors analysed.
4. All scenarios produce pipeline grade CO_2. For the molten carbonate fuel cell (MCFC) and membrane scenarios CO_2 is produced in liquid phase.
5. The MCFC scenarios also consume natural gas and generate electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The 'Other variable OPEX' segment in the MCFC scenarios include both a natural gas cost and a negative operating cost resulting from electricity export.
6. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the EfW and cement sectors, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately.
7. The Low Emissions Intensity Lime and Cement (LEILAC), and partial oxyfuel cement scenarios are process alterations that aid capture, rather than standalone capture technologies. Impacts on the cement manufacturing process may not be reflected in the LCOC values. In new build projects, capital cost reductions would be possible for these technologies as conventional equipment is replaced.
8. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

4.1 Benchmarks

Figure 9. shows the LCOC for the gas fired power generation, EfW and cement manufacture benchmark cases.

Figure 9. Comparison of Benchmarks

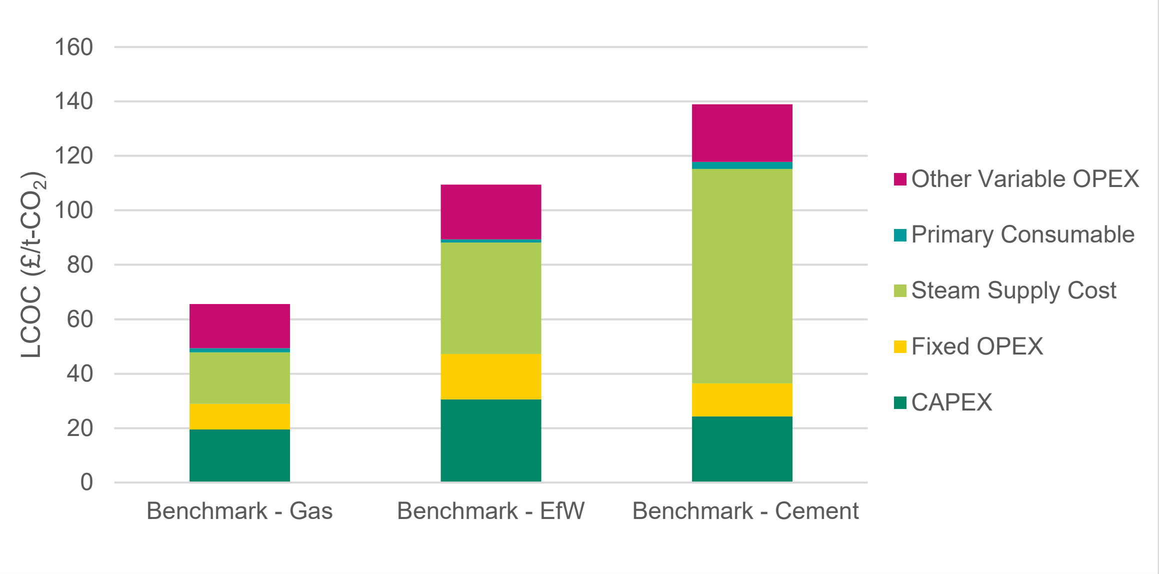


Figure 9. Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% in all benchmark scenarios.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The differences in LCOC values between the benchmarks are principally driven by differences in the assumed unit costs for thermal energy. Thermal energy costs will be influenced by a range of factors including gas price and site-specific integration issues. Understanding the cost and availability of thermal energy is an important step early in the development of a capture project. The LCOC result in the gas power generation benchmark also benefits from economies of scale.

Table 1 provides further information on the benchmark scenarios analysed.

Table 1. Comparison of benchmark scenarios

Parameter	Gas Power	EfW	Cement
Scenario and host plant capacity	New build gas power plant with amine post combustion capture 910 MWe gross electrical output	Existing EfW retrofitted with amine post combustion capture 350,000 tpa of waste	Existing cement plant retrofitted with amine post combustion capture 1 Mtpa of clinker
Capture scale / level	c.6,500 tpd 95%	c.1,000 tpd 95%	c. 2,500 tpd 95%
CAPEX	£402.0m	£96.8m	£192.5m
OPEX	£94.0m/year	£24.7m/year	£89.4m/year
LCOC Not including CO_2 transport and storage	£66/tCO_2	£109/tCO_2	£139/tCO_2
Product	Low carbon electricity (MWh)	Decarbonised residual waste treatment (tonnes)	Decarbonised clinker (tonnes)
Impact on Product Cost (Based on assumed CO_2 emission prices, not including CO_2 transport and storage)	+£30/MWh +47%	+£112/t-MSW +112%	+£121/t-clinker +188%
Opportunities	• Relatively low level of contamination in flue gas • High volumes of CO_2 produced at one source • Economies of scale reduce capture costs • Relatively easy access to thermal energy	• Potential for net negative CO_2 emissions due to biogenic content of feedstock • Consistent high load operation • Experience of complex flue gas treatment • Improved public perception • Limited other options for residual waste treatment	• Potential for net negative CO_2 emissions if feedstock with biogenic content is used • Potential to export low CO_2 product • High volumes of CO_2 produced at one source • Limited other ways of substantially reducing CO_2 emissions resulting from calcination
Challenges	• Competing technologies for low carbon electricity generation • Low CO_2 concentration in flue gas • Gas unlikely to be used for base load generation in a renewables-dominated energy system where its principal role is to provide dispatchable generating capacity. Intermittent use will result in a higher LCOC.	• Integration with existing process plant. • Potential impact of residual contaminant carryover from existing flue gas treatment processes • Dispersed location of sites	• Integration with existing process plant • Cost and availability of low carbon thermal energy • Potential impact of residual contaminant carryover from existing flue gas treatment processes • Other decarbonisation options available for combustion emissions, such as providing financial support for alternatives to coal • Dispersed location of sites • Competition from imported products
Modelling Uncertainty	Medium	Medium	Medium

4.2 Gas Power Generation

Figure 10 shows the LCOC for the gas fired power generation benchmark and the two next generation capture cases applied to gas fired power generation.

Figure 10. Gas Power Generation LCOC

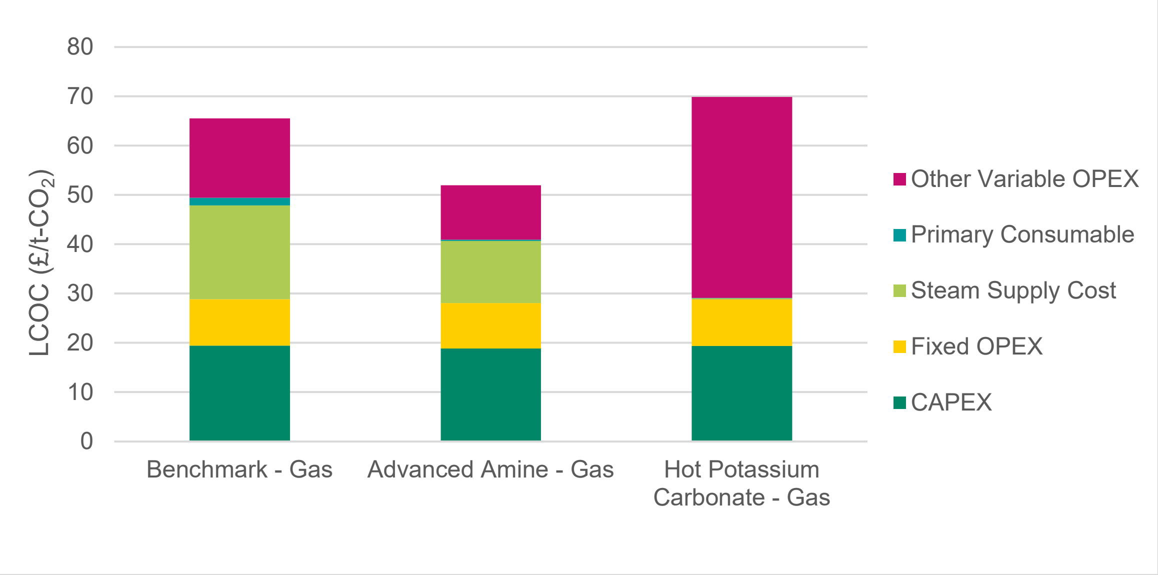


Figure 10 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the Benchmark, 95% for the Advanced Amine and 90% for the Hot Potassium Carbonate scenario.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The advanced amine scenario shows a reduced LCOC relative to the benchmark case. The cost reduction is primarily due to reduced energy consumption.

The hot potassium carbonate scenario shows an increased LCOC relative to the benchmark case. When this technology is applied to an EfW plant later in the report, a reduction in LCOC is observed relative to the EfW benchmark. This is due to the higher concentration of CO_2 in the EfW flue gas, which is of greater benefit to this technology, and the higher assumed cost of thermal energy in the EfW scenario. The hot potassium carbonate technology uses mainly electricity rather than steam. This is most advantageous in situations where access to thermal energy is restricted or expensive. Application of the hot potassium carbonate technology in the cement sector would also be possible where low carbon thermal energy may not be readily available.

Figure 11 shows the impact on product cost and net power export for the gas fired power generation capture technology scenarios.

Figure 11 Gas Power Generation Impact on Product Cost

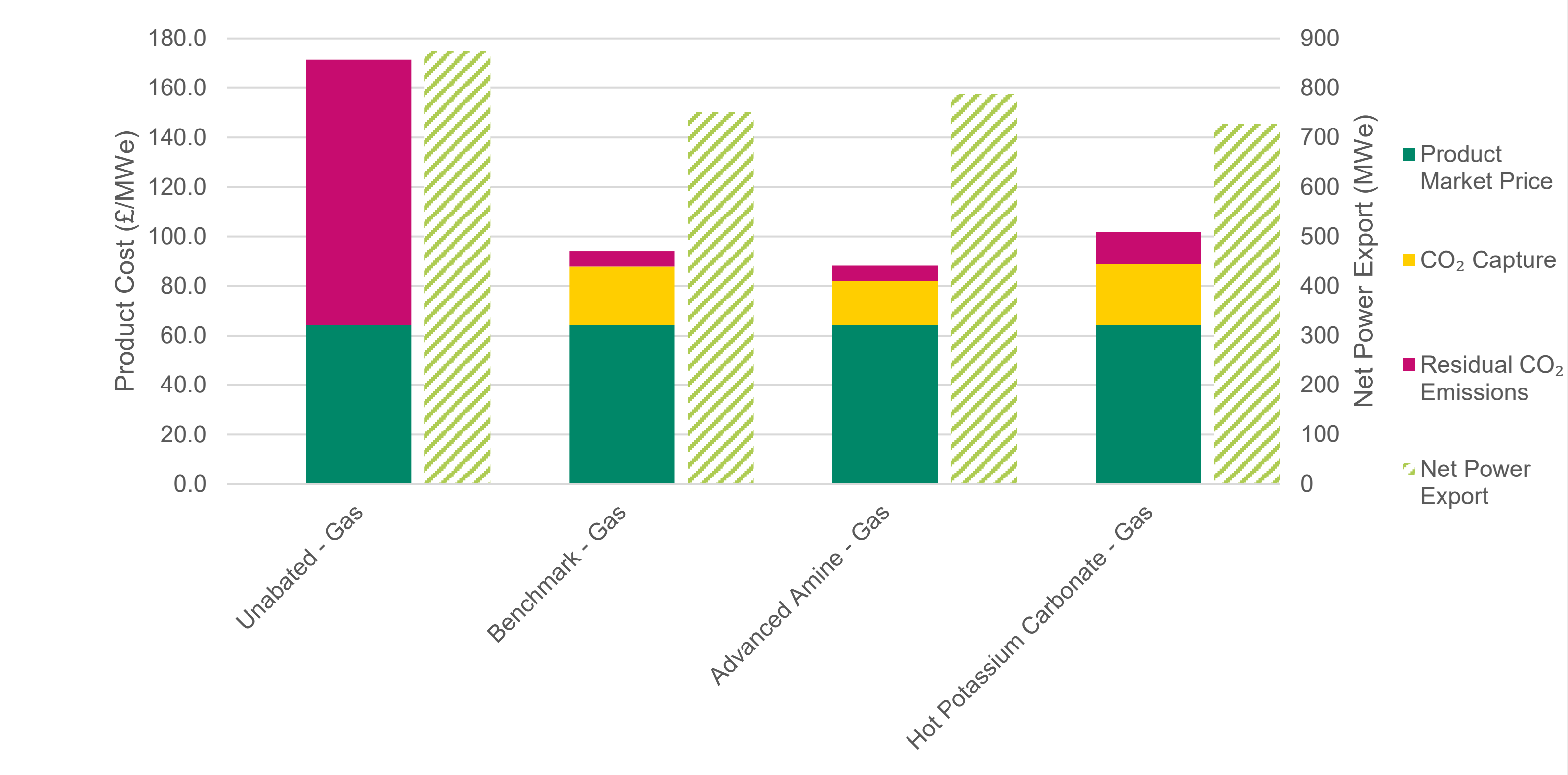


Figure 11 shows the impact on product cost and net power export for the gas fired power generation capture technology scenarios.

Figure 11 **Footnotes**

1. Costs for CO_2 transport and storage are not included.
2. Capture level is 95% for the Benchmark, 95% for the Advanced Amine and 90% for the Hot Potassium Carbonate scenario.
3. Impact on product cost is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Table 2 provides further information on the gas power generation scenarios.

Table 2. Comparison of gas power generation scenarios

Scenario	Benchmark – Gas	Advanced Amine	Hot Potassium Carbonate
Net electrical output	874 MW 751 MW (with capture)	874 MW 788 MW (with capture)	874 MW 728 MW (with capture)
Capture scale / level	6,527 tpd 95%	6,527 tpd 95%	6,184 tpd 90%
CAPEX	£402.0m	£390.5m	£379.1m
OPEX	£94.0m/year	£67.4m/year	£97.7m/year
LCOC (Not including CO_2 transport and storage)	£66/tCO_2	£52/tCO_2	£70/tCO_2
Impact on Product Cost (Based on assumed CO_2 emission prices, not including CO_2 transport and storage)	+£30/MWh +47%	+£24/MWh +38%	+£38/MWh +59%
Opportunities	See benchmark comparison	• Lower availability risk than other next generation technologies • Reduced energy consumption • Incremental improvements throughout process • Minimal scale-up	• A less hazardous, non-proprietary, solvent • Can avoid the use of heat (steam) for solvent regeneration, using electricity instead
Challenges	See benchmark comparison	• Generation of harmful solvent degradation products • Price risk associated with use of a proprietary solvent	• Validation of energy performance • Multiple scale-up steps would be advisable • Achieving a higher CO_2 capture level in a gas power generation application without impacting costs.
Modelling Uncertainty	Medium	Medium	High

4.3 Energy from Waste

Figure 12 shows the LCOC for the EfW benchmark and the six next generation capture cases applied to Energy from Waste plant.

Figure 12. Energy from Waste LCOC

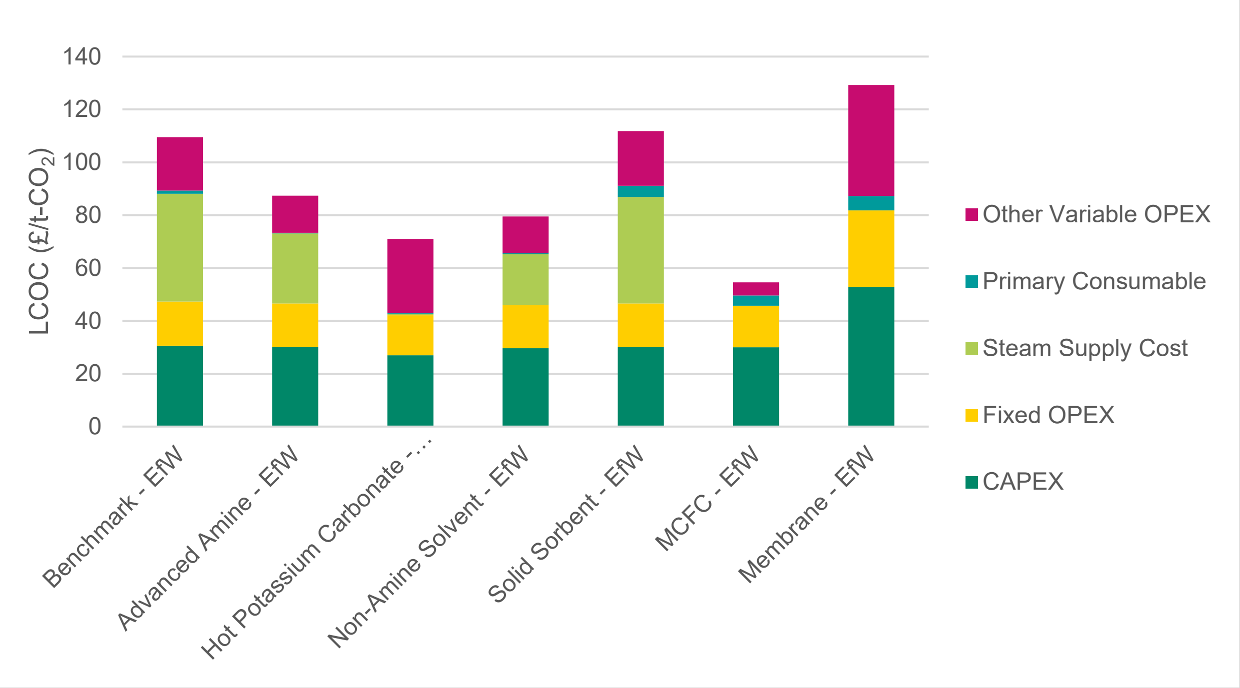


Figure 12 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. All the EfW scenarios process 350,000 tpa of MSW.
3. Capture level is 95% or greater for all scenarios other than the membrane scenario which has a capture level of 60%. Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
4. All scenarios produce pipeline grade CO_2. For the MCFC and membrane scenarios the CO_2 is produced in the liquid phase.
5. The MCFC scenarios also consume natural gas and generate electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The ‘Other variable OPEX’ segment in the MCFC scenarios include both a natural gas cost and a negative operating cost resulting from electricity export.
6. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the EfW and cement sectors, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately.
7. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Further information is provided in Table 3, with additional commentary on results provided in the scenario write-ups. Figure 13 shows the impact on product cost for the EfW scenarios.

Figure 13 Energy from Waste Impact on Product Cost

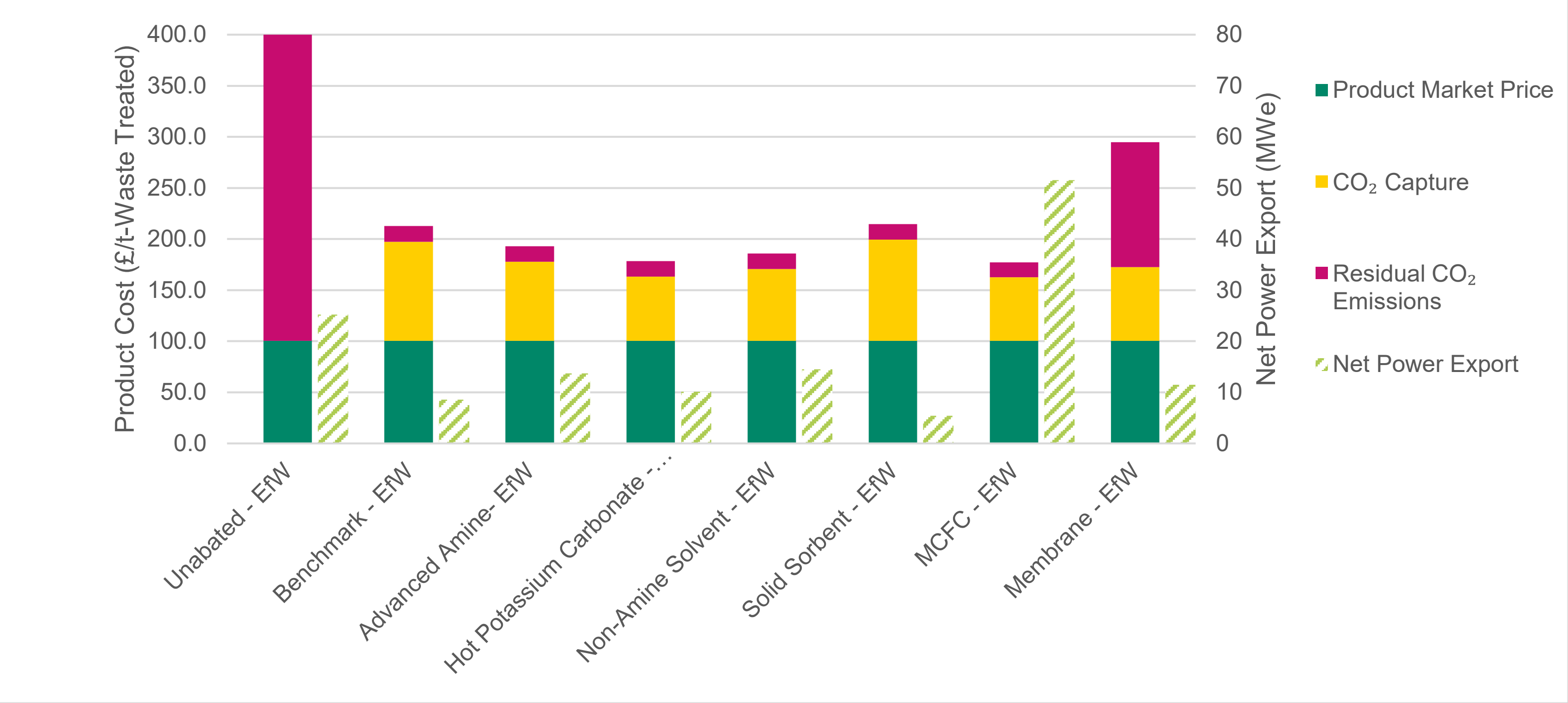


Figure 13 Footnotes

1. Costs for CO_2 transport and storage are not included.
1. All the EfW scenarios process 350,000 tpa of MSW.
2. Capture level is 95% or greater for all scenarios other than the membrane scenario which has a capture level of 60%. Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
3. All scenarios produce pipeline grade CO_2. For the MCFC and membrane scenarios the CO_2 is produced in the liquid phase.
4. The MCFC scenarios also consume natural gas and generate electricity. Therefore, impact on product cost will be influenced by the economics of power generation from gas in a way that other capture technologies are not.
5. More CO_2 is captured in the MCFC case, relative to the other EfW scenarios, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the EfW process, and hence LCOC is reduced commensurately.
6. Product cost impact is only one aspect of performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Table 3. EfW Scenarios

Scenario	EfW Benchmark	Improved Amine	HPC	Non-amine solvent	Solid Sorbent	MCFC	Membrane
Net electrical output	25 MW 9 MW (with capture)	25 MW 14 MW (with capture)	25 MW 10 MW (with capture)	25 MW 15 MW (with capture)	25 MW 5 MW (with capture)	25 MW 52 MW (with capture)	25 MW 11 MW (with capture)
Capture scale / level	c.1,000 tpd 95%	c.1,000 tpd 95%	c.1,000 tpd 95%	c.1,000 tpd 95%	c.1,000 tpd 95%	c. 1,288 tpd, 96%, liquid phase (Additional CO_2 from fuel)	c. 632 tpd 60%, liquid phase
CAPEX	£96.8m	£95.5m	£85.5m	£94.0m	£95.4m	£122.3m	£105.7m
OPEX	£24.7m/year	£17.9m/year	£13.8m/year	£15.5m/year	£25.5m/year	£9.9m/year (Includes electricity sales)	£15.0m/year
LCOC (Not including CO_2 transport and storage)	£109/tCO_2	£87/tCO_2	£71/tCO_2	£79/tCO_2	£112/tCO_2	£55/tCO_2	£129/tCO_2
Impact on Product Cost (With assumed CO_2 prices, not including CO_2 transport and storage)	+£112/t-MSW +112%	+£93/t-MSW +92%	+£78/t-MSW +78%	+£86/t-MSW +85%	+£114/t-MSW +114%	+£77/t-MSW +77%	+£195/t-MSW +194%
Opportunities	See benchmark comparison	• Lower availability risk than other next generation technologies • Reduced energy consumption • Incremental improvements throughout process • No scale-up required	• Less hazardous solvent • Use of electrical energy rather than thermal could aid integration with the host plant	• Less hazardous solvent • Potentially reduced energy consumption • Potentially reduced solvent costs	• Development of new sorbents to improve performance • Low hazard sorbent • Potentially reduced energy consumption	• An initially small project could be extended with additional modules • Provides low carbon electricity and could produce hydrogen • Use of natural gas rather than steam could aid integration with host plant • No reliance on chemical solvents.	• Use of electrical energy rather than thermal could aid integration with the host plant • Modular construction • No reliance on chemical solvents or fuels. • Operational flexibility
Challenges	See benchmark comparison	• Generation of harmful solvent degradation products • Price risk associated with proprietary solvent	• Validation of energy performance • Lack of operational experience on EfW flue gas	• Validation of energy performance • Lack of operational experience on EfW flue gas	• Pilot plants are of limited scale • Lack of operational experience on EfW flue gas	• Additional contaminant removal from input gases is required • Dependant on natural gas	• Low capture level without additional capture technology • Lack of operational experience on EfW flue gas

Scenario	EfW Benchmark	Improved Amine	HPC	Non-amine solvent	Solid Sorbent	MCFC	Membrane
				• Price risk associated with proprietary solvent		• Lack of operational experience on EfW flue gas	
Modelling Uncertainty	Medium	Medium	High	High	High	High	High

4.4 Cement Manufacture

Figure 14 shows the LCOC for the cement manufacture benchmark and next generation cases.

Figure 14. Cement Manufacture LCOC

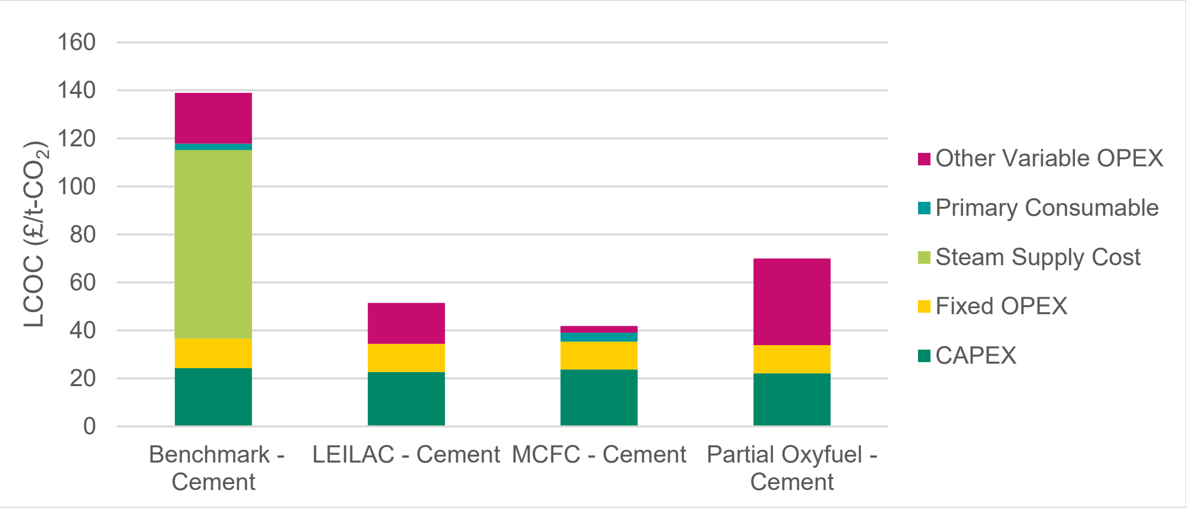


Figure 14 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. All the cement scenarios manufacture 1Mtpa of clinker.
3. Capture level is 95% for the benchmark and MCFC scenarios, 60% for LEILAC and 60% for the partial oxyfuel scenario. Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
4. All scenarios produce pipeline grade CO_2. For MCFCs CO_2 is produced in liquid phase.
5. The MCFC scenarios also consume natural gas and generate electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The ‘Other variable OPEX’ segment in the MCFC scenarios include both a natural gas cost and a negative operating cost resulting from electricity export.
6. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the cement sector, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately.

7. The Low Emissions Intensity Lime and Cement (LEILAC) and partial oxyfuel cement scenarios are process alterations that aid capture, rather than standalone capture technologies. Impacts on the cement manufacturing process may not be reflected in the LCOC values. In new build projects, capital cost reductions would be possible for these technologies as conventional equipment is replaced.
8. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

In the LEILAC and partial oxyfuel scenarios higher capture levels could be achieved by adding an additional capture technology. Figure 15 shows the impact on product cost for the cement manufacture scenarios.

Figure 15 Cement Manufacture Impact on Product Cost

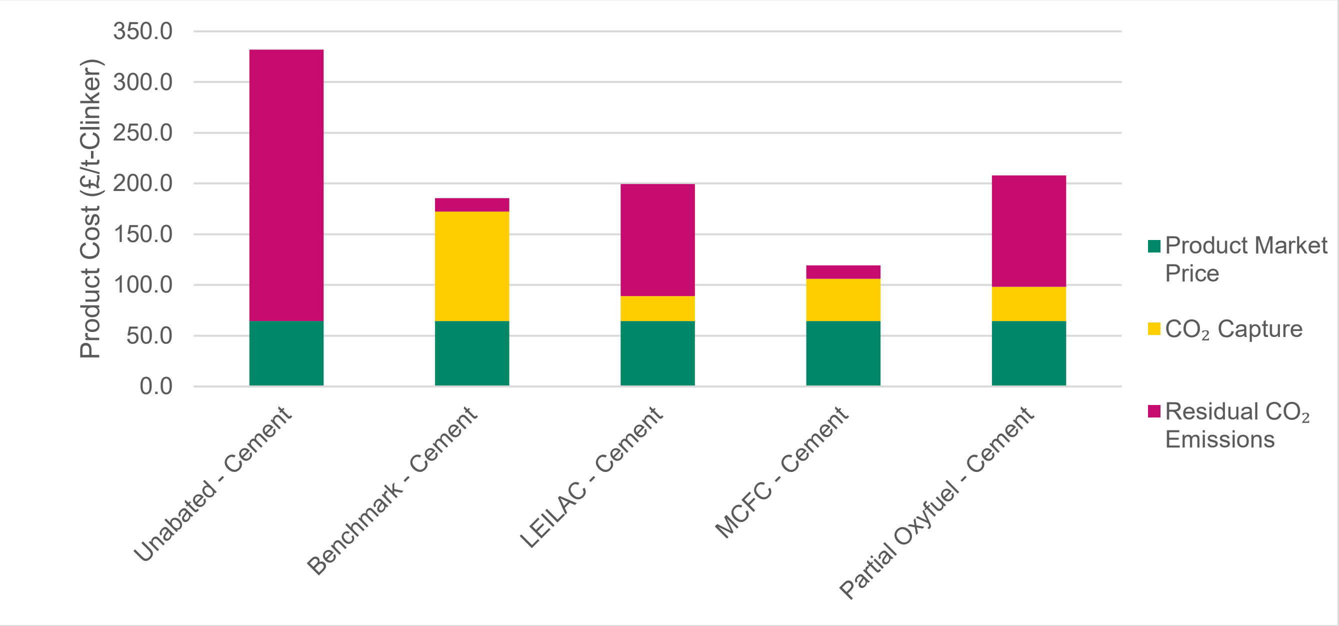


Figure 15 Footnotes

1. Costs for CO_2 transport and storage are not included.
2. All the cement scenarios manufacture 1Mtpa of clinker.
3. Capture level is 95% for the benchmark and MCFC scenarios, 60% for LEILAC and 60% for the partial oxyfuel scenario. Based on assumed CO_2 emission prices, residual emission costs and the impact on product cost will be higher where capture levels are lower.
4. All scenarios produce pipeline grade CO_2. For MCFCs CO_2 is produced in liquid phase.
5. The MCFC scenarios also consume natural gas and generate electricity. Therefore, impact on product cost will be influenced by the economics of power generation from gas in a way that other capture technologies are not.
6. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the cement sector, due to capture of the CO_2 from the natural gas used.

7. The Low Emissions Intensity Lime and Cement (LEILAC) and partial oxyfuel cement scenarios are process alterations that aid capture, rather than standalone capture technologies. Impacts on the cement manufacturing process may not be reflected in the Impact on Product cost values. In new build projects, capital cost reductions would be possible for these technologies as conventional equipment is replaced.
8. Product cost impact is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

With the assumed CO_2 emission prices, the impact on product cost is higher in technology scenarios with lower capture levels. This is due to the relatively high cost of emitting residual CO_2 to the atmosphere. If CO_2 emission prices were lower, then a solution offering an attractive LCOC, but with a lower capture level, may give a lower overall cost of product.

Further information is provided in Table 4.

Table 4. Cement Scenarios

Scenario	Benchmark	LEILAC	MCFC	Partial Oxyfuel
Capture scale / level	c.2,500 tpd 95%	c. 1,547 tpd, 60% (Combustion emissions not captured)	c. 3,205 tpd, 96% (Additional CO_2 from fuel)	c. 1,549 tpd, 60% (Kiln emissions not captured)
CAPEX (£m)	£192.5m	£111.1m*	£240.7m	£108.6m
OPEX (£/year)	£89.4m/year	£13.7m/year	£18.3m/year (Includes electricity sales)	£22.8m
LCOC (£/tCO_2) (Not including CO_2 transport and storage)	£139/tCO_2	£51/tCO_2	£42/tCO_2	£70/tCO_2
Impact on Product Cost (Based on assumed CO_2 emission prices, not including CO_2 transport and storage)	+£121/t-clinker +188%	+£135/t-clinker +209%	+£55/t-clinker +85%	+£144/t-clinker +223%
Opportunities	See benchmark comparison	• Process alterations to aid capture can offer cost and energy savings • Potential to operate on a range of fuels or electricity • May be applicable in limited range of other industries e.g. iron, steel, lime, selected other mineral products.	• An initially small project could be extended with additional modules • Provides low carbon electricity and could produce hydrogen • Use of natural gas rather than steam could aid integration with the host plant	• Potential for other process benefits including increased plant capacity or use of fuels with lower calorific value. • The primary input being electrical rather than thermal could be an advantage at some sites • No reliance on chemical solvents
Challenges	See benchmark comparison	• Availability issues could impact the host plant • Anticipated performance for key parameters remains to be demonstrated • Low capture level without additional capture technology	• Lack of operational experience on cement flue gas • Additional contaminant removal from input gases is required • Dependant on natural gas	• Complex modifications required to existing equipment. • Availability issues could impact the host plant • Low capture level without additional capture technology
Modelling Uncertainty	Medium	Very High	High	Very High

*In a new build plant, or if a replacement precalciner is required, the capital cost for a conventional precalciner could be subtracted from this value because the LEILAC reactor is a replacement for standard precalciner equipment.

5. Summary of Assumptions

Understanding and appropriate use of the outputs from the technoeconomic analysis is dependent on an understanding of the assumptions and quality of input data used in the analysis. The following summary of assumptions and associated uncertainties is intended to provide clarity on the evidence base used for the analyses and an indication of where the important areas of risk and uncertainty lie.

Data and assumptions used in the technoeconomic modelling have been gathered from a variety of sources. Where possible, publicly available information has been used from journals, academics studies and third-party publications. In addition, an extensive consultation exercise was conducted involving technology providers to obtain as much information for the study as possible.

When studying emerging technologies, there are unavoidably performance data that do not exist. For example, the long-term maintenance costs of an item of equipment that has never operated for a long time, or capital cost of plant and equipment that has never been built at that scale. These data can significantly impact the results of the analysis. Where information is absent or appears unreliable, engineering judgement has been used to inform assumptions as necessary to complete the assignment.

Our understanding of the limitations of the data has been used to inform the commentary provided on the uncertainty associated with the scenarios investigated. Understanding the strengths and weaknesses of the data available is essential in relation to interpreting the resulting comparison between emerging technologies. Each scenario has been given an overall uncertainty rating of *medium*, *high* or *very high*. These ratings are based on an overall professional opinion on the uncertainties associated with the scenario, noting that some assumptions have a greater potential to impact the results obtained.

5.1 Quality, Impact and Uncertainty Definitions

In undertaking the technoeconomic assessment, an uncertainty rating for each assumption in the models has been allocated by assessing the quality of the data source and the impact of the assumption on the model outputs. Table 5 provides definitions for the quality and impact ratings used.

Table 6 shows how these translate into uncertainty ratings for the assumptions made.

Where quality and / or impact ratings for a parameter are listed as variable, further information relating to the parameter has been provided in the write-ups of the individual scenarios. Consideration has been given to the BEIS Quality Assurance requirements during the gathering of data and presentation of assumptions.

Table 5. Quality and impact rating definitions

Rating	Definition	Grade	Explanation
Quality Rating	This assesses the certainty and / or robustness of a data source. If the data is manipulated or transformed in some way, the quality decreases. A wide confidence interval (e.g., ±50%) would have a low quality rating.	High	The value is based on real data and transformations are minimal or robust. The data is current and there is a narrow confidence interval.
		Medium	Value is based on limited data, but reasoning is robust. There has been significant manipulation to the data and the confidence interval is wide.
		Low	There is either no data source or an unreliable data source has been used. Quality rating may also be low if a robust data source is used but the data is likely to change significantly over the model period.
Impact Rating	This assesses the sensitivity of the model outputs to variations in inputs. Rating should reflect the relative change in output when input value is changed.	Low	A change in input value has negligible impact on model outputs.
		Medium	A change in input value has some impact on model outputs.
		High	A change in input value has significant impact on model outputs and could affect decision making.
Uncertainty Rating	This assesses which assumptions need to be highlighted.	Low	Assumption has low impact and source is of good quality. Very little can be done to improve.
		Medium	Assumption has medium impact on model outputs. Changes would affect results but not significantly.
		High	Assumption has high impact on model outputs. Changes have the potential to affect results significantly.
		Very High	Assumption has a very high impact on model outputs. Changes are likely to affect results significantly.

Table 6. Summary of uncertainty ratings based on impact and quality rating

Uncertainty Rating		**Impact Rating**		
		Low	**Medium**	**High**
Quality Rating	**High**	Low	Medium	High
	Medium	Low	High	Very High
	Low	Medium	Very High	Very High

5.2 Model Setup Assumptions

Table 7 provides details of model setup assumptions.

Table 7. Model setup assumptions

Modelling Assumption	Value	Data Quality	Model Impact	Uncertainty	Comment
Cost basis year	2025	High	Low	Low	The cost basis year selected has a limited impact on comparative model outputs.
Discount rate	7.8%	High	Medium	Medium	When model outputs are used for the intended purpose of comparing carbon capture technologies, the discount rate has a limited impact on results, although the selected discount rate may impact the comparison with other study work or alternative decarbonisation options.

Modelling Assumption	Value	Data Quality	Model Impact	Uncertainty	Comment
Design life	25 years	High	Low	Low	Plant design life has a limited impact on model outputs.
Capture level	95%	High	Low	Low	The capture level has been selected for the purposes of comparing the technologies. Any scenario that is unlikely to meet or exceeds this capture level has been highlighted.
Plant availability	85%	Variable	Variable	High Potential	The ability of plants to work reliably is fundamental to project economics. This study relates to emerging technologies with limited demonstrated operation. Comments have been provided on the relative availability uncertainty of different technologies.
Input gas composition	See Appendix B	Variable	Variable	High Potential	For many industries there could be considerable variation in input gas composition depending on the fuels used.
CO_2 export specification	See Appendix B	High	Medium	Medium Potential	Changes to CO_2 export pressure and composition requirements could impact capture costs.

5.3 Capital Cost Assumptions

Table 8 provides details of capital cost assumptions used in the modelling.

Table 8. Capital cost assumptions

Modelling Assumption	Value	Data Quality	Model Impact	Uncertainty	Comment
Construction period	3 years	High	Low	Low	Based on experience of constructing process plants of similar scale and complexity.
EPC Contract price	Calculated for each scenario	Medium	Medium	High	There is unavoidable uncertainty associated with estimating construction costs for emerging technologies.
Land purchase price [1]	£21.34/m^2	Medium	Low	Low	Land costs will vary depending on location. However, for technology comparison land cost has a limited impact.
Consultancy costs [2]	1% of EPC Cost	Medium	Low	Low	Consultancy costs vary between projects but the overall impact on results is limited.
Planning and other regulatory costs	2% of EPC Cost	Medium	Low	Low	Planning and regulatory costs vary between projects and can make projects unviable. However, for technology comparison the overall impact on results is limited.
Developer's costs [3]	7% of EPC Cost	Medium	Low	Low	Developer's costs vary between projects but the overall impact on results is limited.
Start-up and commissioning costs [2]	5% of EPC Cost	Medium	Medium	High	Start-up and commissioning cost is a significant uncertainty for emerging technologies. Comments have been provided on the relative uncertainty of different technologies.
Utility connection costs	1% of EPC Cost	Medium	Low	Low	Utility connection costs vary between projects and can make projects unviable. For the purposes of technology comparison, the overall impact on results is limited.
Developer contingency	10% of total capital	Medium	Low	Low	Contingency levels assumed by developers will vary between projects but the overall impact on results is limited.

5.4 Operating Cost Assumptions

Table 9 provides details of operating cost assumptions used in the modelling.

Table 9. Operating cost assumptions

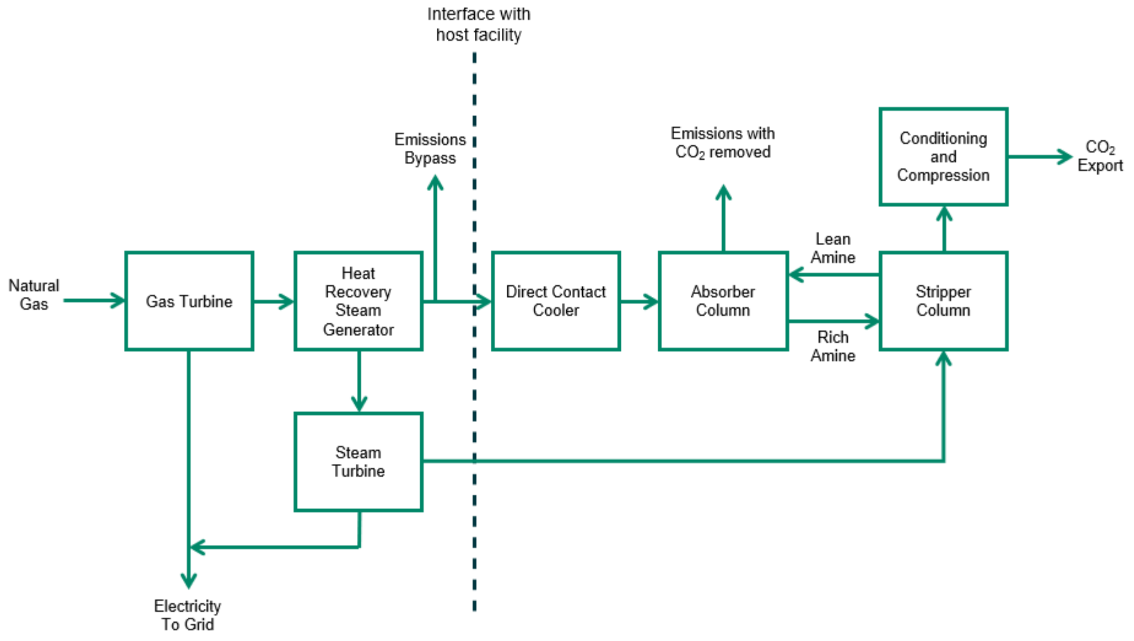
Modelling Assumption	Value	Data Quality	Model Impact	Uncertainty	Comment
Fixed Operating Costs					
Labour cost	From staffing costs and numbers	Medium	Low	Low	Values for each role are based on Office for National Statistics values for average employee earnings in the UK and escalated to 2025 prices. Quality is medium due to uncertainty in staffing numbers required.
Administration and other overheads [4]	1.5% of EPC Cost	Medium	Low	Low	Overall impact on technology comparison results is limited.
Maintenance	2.5% of Total CAPEX	Variable	Variable	High Potential	There is unavoidable uncertainty associated with estimating maintenance costs for emerging technologies.
Variable Operating Costs					
Electricity unit cost [5] [6]	See Methodology	High	Variable	High Potential	Values taken from BEIS publications. The impact, and therefore uncertainty, of this assumption varies depending on the electricity consumption of each scenario. Where power is generated by the base process plant (EfW or gas) electricity cost for the capture plant is parasitic, and hence is based on the opportunity cost of lost revenue from sale of electricity.
Electricity consumption	Variable between scenarios	Variable	Variable	High Potential	The uncertainty associated with consumption figures varies between scenarios. Some reliance has been placed on supplier data, with sense checks conducted as appropriate.
Steam price	Variable between scenarios	Variable	Variable	High Potential	Steam cost is industry and site specific and has a high impact on the results obtained for many of the scenarios.
Steam consumption	Variable between scenarios	Variable	Variable	High Potential	The uncertainty associated with consumption figures varies between scenarios. Some reliance has been placed on supplier data, with sense checks conducted as appropriate.
Emission of CO_2 to atmosphere	See Methodology	Low	Variable	High Potential	Values taken from BEIS publication. The cost of emitting CO_2 to the atmosphere will impact all scenarios. The impact of an increased cost of emitting CO_2 to the atmosphere will be greatest on projects with the lowest capture rates.
Primary consumables (solvents, sorbents, membranes)	Variable between scenarios	Variable	Variable	High Potential	The cost and consumption rate of key consumables is uncertain in some technologies and has a potentially high impact on project economics.
Natural gas [5]	See Methodology	High	Medium	Medium	Values taken from BEIS publications. Few of the scenarios directly use natural gas. However, fluctuations in gas cost could impact project economics by impacting the market price of products.
Natural gas consumption	Variable between scenarios	Variable	Variable	Medium Potential	Most of the scenarios do not directly use natural gas.
Town's water [7]	£0.26/m^3	High	Low	Low	Unlikely to be a key operating cost for the scenarios investigated.
Demineralised water [8]	£0.52/m^3	High	Low	Low	Unlikely to be a key operating cost for the scenarios investigated.
Wastewater discharge [8]	£1.26/m^3	High	Low	Low	Unlikely to be a key operating cost for the scenarios investigated.
Hazardous waste [9]	£166/t	Medium	Low	Low	Unlikely to be a key operating cost for the scenarios investigated.
Secondary consumables (e.g., acid or caustic)	Variable	Medium	Low	Low	Unlikely to be a key operating cost for the scenarios investigated.

6. Gas Power Benchmark

6.1 Description of Scenario

This benchmark scenario involves a new build combined cycle gas turbine (CCGT) power plant with a gross electrical output of 910 MWe fitted with a post combustion amine solvent carbon capture plant. Figure 16 shows a block flow diagram of the process.

Figure 16. Block Diagram – CCGT with amine capture



The Emissions Bypass stream indicated in Figure 16 is where the emissions would exit if the main process plant were to operate without the carbon capture plant. Although not shown explicitly in this diagram, it is assumed that electricity consumed by the capture plant will be provided by the power plant. Being able to import electricity from the base process plant is an advantage relative to non-power cases as the unit cost will be lower than if electricity were purchased from the grid.

The benchmark scenario uses 35% w/w MEA solution as a solvent. Performance information is readily available for this solvent, and the solvent can be sourced from a variety of suppliers. It has been adopted as the benchmark technology for this study as it provides robust, known performance that can be applied as a consistent reference technology for all next generation scenarios assessed.

Leading suppliers of amine solvent capture plants will generally offer a proprietary amine blend solvent with claims of improved performance. Assessing the relative performance of current proprietary amines is outside the scope of this study. However, the study includes advanced amine scenarios for EfW and gas power generation based on process and solvent developments anticipated to be available in the 2030-35 timescales.

A summary of technical information for the base process and carbon capture plant is presented in Table 10.

Table 10. Gas Benchmark – Configuration summary

Item	Description
Base Process Plant	**New build CCGT power plant**
Power output	Single H-class gas turbine with HRSG and condensing steam turbine 910 MW gross electrical output 874 MW net electrical output without carbon capture 751 MW net electrical output with carbon capture Net electrical efficiency 54.4%, including electricity consumption by carbon capture
Flue gas output	3686 tph 5 mol% CO_2
Flue gas treatment	Low NO_X burners SCR to control NO_X SO_X abatement not required for natural gas consumption Particulate abatement not required for natural gas consumption
Carbon Capture Plant	**Post Combustion MEA solvent**
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure and allow admission into downstream process units Direct contact cooler to reduce temperature
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Basic thermal integration of stripper and absorber columns Steam powered reboiler on stripper column Single stage thermal reclaiming
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	35% w/w Monoethanolamine (MEA)
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation Greenhouse gas emissions from natural gas production are not included
Operational hours	7,446 hours/year (8,760 hours * 85%)
CO_2 export pressure	100 barg for export pipeline
Mass of CO_2 captured	272 tph (6,527 tpd)
Steam supply	292 MWth from main power plant This steam use represents the overall heat load of the capture plant and not just the stripper column reboiler
Electricity supply	42 MW from main power plant

6.1.1 Flue Gas Pre-treatment

Combustion of low sulphur natural gas, typical of the UK gas grid, results in acceptable levels of SO_X and particulate matter emissions. A new build plant and a flue gas that is relatively low in contaminants are advantages in relation to the interface with the capture plant and flue gas pre-treatment required.

The NO_X produced during the gas combustion process will be controlled using a combination of low NO_X burner technology and selective catalytic reduction (SCR). We would expect these NO_X control technologies to be used on a gas power plant of this type regardless of whether a capture plant was associated with the power plant, and to provide NO_X levels that are acceptable for the capture plant.

6.1.2 Thermal Energy

In a new build gas fired power plant thermal energy, in the form of steam, can be supplied as required by extracting from the steam turbine. The unit cost of the steam is proportional to the lost potential revenue from reduced electrical output. For all post combustion capture plants associated with gas fired power generation in this study it has been assumed that one unit of reduced electrical output provides 4.2 units of thermal energy in the form of steam. The ratio between thermal energy extracted and lost electrical output is a representative figure for gas fired power plants. Actual reductions in electrical output as steam is extracted will vary depending on several factors including extraction pressure, steam cycle configuration and extraction volume. More detailed analysis of the relationship between steam extracted and lost electrical output should be conducted during the development of capture projects for specific sites. With this assumed performance, the unit cost for steam in any given year of the model will be the wholesale electricity price for that year divided by 4.2.

MEA based post combustion capture systems thermal energy requirements are relatively well established and easy to access. A conservative basis of MEA performance has been assumed for the benchmark scenario. As an example of publicly available information on MEA performance, in 2021 the Technology Centre Mongstad published information and learnings on MEA based capture from CCGT emissions based on their trial campaign, including data on optimal reboiler duty and other key parameters [10].

None of the scenarios in this study use steam powered drives to operate major items of equipment such as compressors or blowers. This is an option that projects may wish to consider during the engineering design and optioneering phase of project development.

6.1.3 Current Demonstration Status

Amine based carbon capture on gas fired power plants is rare because of the current low cost associated with emitting CO_2 emissions to the atmosphere. Examples of this technology include the 320-350 tpd Bellingham Gas Power Plant, Massachusetts, USA, that operated between 1991 and 2005 [11], and a 1000 tpd plant in Lubbock, Texas, that provided CO_2 for enhanced oil recovery in the 1980s. Both plants were built by Fluor [12]. Testing of primary amine solvents using different flue gases has also been conducted at the Technology Centre Mongstad (TCM) in Norway.

The largest post combustion amine-capture plants that have been built were retrofitted to coal fired power plants. These include MHI’s 4,700 tpd Petra Nova coal-fired power plant in Texas, USA [13] and Shell’s 3,000 tpd plant at Saskpower’s Boundary Dam coal-fired power station in Saskatchewan, Canada [14]. Despite the difference in flue gas characteristics and solvent blends, these are important references in relation to building amine solvent capture plants at scale.

There are development plans for utility scale gas fired power generation with amine-based carbon capture in the UK.

6.1.4 Technology Development

Amine based carbon capture on gas fired power generation has been demonstrated over extended periods of time and at a relevant scale. The main barriers to implementation of amine-based carbon capture on gas power generation are primarily economic rather than relating to the availability of suitable technology. Nevertheless, there is uncertainty in relation to plant cost and performance because there are so few working examples of post combustion carbon capture plants on gas fired power generation.

If more amine-based carbon capture on gas fired power plants were constructed and operated there would be a reduction in cost and performance uncertainty. Improvements in plant cost and performance, relative to the first plants constructed, could be anticipated through incremental improvements to solvents, process plant and construction techniques. Commentary on areas for improvement in relation to solvent based carbon capture plants is provided in Section 2.2 of the *Review of Next Generation Carbon Capture Technologies* report.

Flue gas from gas fired power generation has a relatively low level of contaminants and particulates relative to input gas streams from other industries and this is an advantage in relation to operation of a post combustion capture plant. However, flue gas from gas power generation has a relatively low CO_2 concentration and high oxygen concentration relative to other industrial flue gases and these characteristics make carbon capture more challenging.

Furthermore, there is greater potential for gas fired power generation assets to be operated intermittently when compared to other CO_2 emissions sources. Intermittent operation can reduce plant efficiency and would mean a lower utilisation of the capital investment required for the capture plant. For intermittent operation capital costs make up a bigger proportion of the overall cost of capture. This increases the need for, and value of, technology developments that allow capital cost reductions. AECOM has conducted work on behalf of BEIS in relation to efficiency savings for capture plants not operating on a continuous basis.

Hazards

The development of capture technology will create new hazards in relation to the transport and storage of CO_2. Understanding and mitigating these hazards is important in relation to the development and operation of capture technologies. However, these hazards are not considered further in this assignment as they are not directly related to the capture technology.

Amine solvent capture processes have the potential to release solvent or harmful solvent degradation products into the environment. The extent of this issue will depend on a variety of factors, including what amine is being used as the solvent. Primary amines, as have been assumed in all benchmark cases, generally have less propensity to degrade to nitrosamines than secondary amines that may be used in advanced amine systems. However, nitrosamines remain a concern as they can be toxic, mutagenic, and carcinogenic. It is important to understand the formation, nature and management of degradation products generated by amine solvents.

For safety hazards relating to a process, elimination of the hazard should be the first option considered, prior to reduction, isolation, and control of the hazard. The hazard associated with exposure to amine solvent or amine solvent degradation products has the potential to be eliminated by using alternative solvents. Some of the scenarios analysed in this study involve the use of more benign, non-amine solvents.

There may be cost, or energy penalties associated with using alternative solvents and mitigation measures can be taken to reduce the likelihood of harmful exposure to amine degradation products. The residual risk of exposure to amine degradation products needs to be balanced against any cost and performance penalties associated with using alternative solvents that have less potential to cause harm.

The combined environmental impacts of the energy use, chemicals consumption, generation of wastes and risk of unintended release of solvents or solvent degradation products needs to be balanced against the beneficial environmental impacts of reducing CO_2 emissions to the atmosphere.

Maintenance

An overview of maintenance requirements for key items of equipment is provided below.

- **Columns** – Absorption and stripping columns will require periodic inspection of internals and ancillary components. Fouling may occur in certain areas of the column and periodic cleaning will be required. Due to their large physical size replacement of column internals has the potential to be a high-cost maintenance activity and will involve hazardous activities such as working at heights.
- **Fans and Compressors** – Fans and compressors are used across the process: for increasing the pressure of the flue gas prior to entry into the capture plant, compression of CO_2 captured and dissipation of low-grade heat to the atmosphere. Necessary maintenance activities for fans and compressors include inspection and maintenance of mounting hardware, blades, housings, bearings, couplings and electrical components.
- **Pumps** – Pumps are used across the process for moving solvent around the cycle, moving water and waste products and dosing of chemicals. Some of the pumps in the system are exposed to challenging process conditions. Necessary maintenance activities for pumps include inspection and maintenance of mounting hardware, impellors, casings, bearings, couplings and electrical components.
- **Heat exchangers** – Heat exchangers will be designed with suitable allowances for fouling and corrosion during normal operation under the anticipated process conditions. Nevertheless, heat exchangers will require periodic inspection and maintenance, with replacement of parts as necessary. Some heat exchangers will require periodic cleaning.
- **Ancillary systems –** The capture plant is a complex process plant with ancillary systems that require ongoing maintenance during the life of the asset. Ancillary systems include wastewater treatment, process pipework, steam and condensate distribution and collection, electrical systems, control systems, chemical handling and storage, nitrogen, instrument air, fire detection and suppression, staff welfare facilities and site infrastructure.

For all items of equipment, the level of maintenance required will be dependent on the quality of the original design and build, the way that the plant is maintained and operated, and the quality of material inputs from upstream process units. Reliability and maintainability studies can be used to determine appropriate equipment redundancy requirements and system configuration.

6.2 Cost Summary

Table 11 and Table 12 contain a summary of the capital and annual operational costs for this benchmark scenario.

Table 11. Gas Benchmark – Capital cost

Item	Cost
EPC Costs	
Gas Power Plant	NA
Flue Gas Pre-Treatment	£47.1m
Capture Technology	£96.3m
CO_2 conditioning	£3.7
CO_2 compression	£32.9m
Auxiliary Systems	£76.5m
Civil works	£57.6m
Total EPC	**£314.0m**
Project Development Costs	
Land Requirements	£1.3m
Utility & Infrastructure Connections	£3.1m
Consultancy	£3.1m
Planning & Other Regulatory	£6.3m
Developer's Costs	£22.0m
Start-Up & Commissioning	£15.7m
Total Project Development	**£51.5m**
Total Capital Cost	
Total Capital Cost	£365.5m
Contingency	10%
Grand Total CAPEX	**£402.0m**

Table 12. Gas Benchmark – Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£1.4m
Administration and other overheads	£6.0m
Maintenance	£10.1m
Total Fixed OPEX	**£17.5m**
Variable Costs	
Natural Gas	NA
Electricity	£21.1m
Steam supply	£35.2m
Solvent	£2.8m
Other chemicals and consumables	£1.8m
Wastes	£6.7m
Plant auxiliary	£0.3m
Total Variable OPEX	**£68.0m**
Total Operating Cost	
Total Operating Cost	£85.4m
Contingency	10%
Grand Total OPEX	**£94.0m**

6.3 Key Outputs

Table 13 contains a summary of values relating to the LCOC.

Table 13. Gas Benchmark – Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	2.0 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	50.6 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	18.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£402.0m	
Average total annual OPEX	£94.0m	
Lifetime cost	£2,751.2m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£1,240.5m	Adjusted lifetime cost value based on discount rate.
LCOC	**£66/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart representing the LCOC and its constituent components is provided in Figure 17.

Figure 17. Gas Power Benchmark LCOC

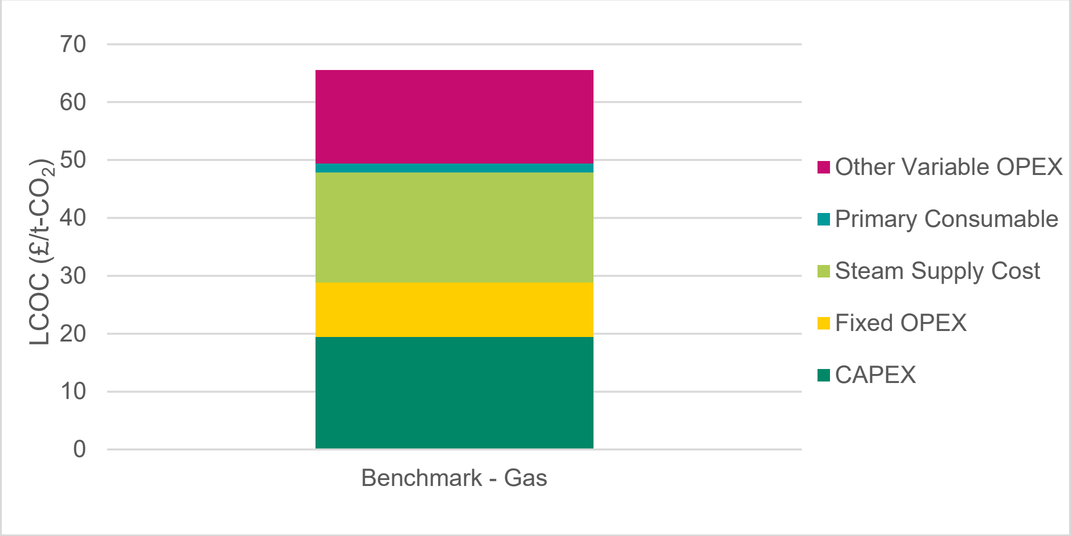


Figure 17 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95%.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Table 14 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 14. Gas Benchmark – Impact on product cost

Item	Value	Comment
Product produced	Electricity	
Lifetime electricity produced	139,832 GWh	Net production with capture
Lifetime CO_2 captured	50.6 Mt	
LCOC	£66/t	From calculations above
Lifetime CO_2 residual emissions	2.7 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£36.9m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64/MWh	Price includes no additional cost to the host plant for emission of CO_2 to the atmosphere.
Product cost with impact of capture only	£88/MWh +£24/MWh +37% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£70/MWh +£6/MWh +10% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£94/MWh +£30/MWh +47% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£171/MWh +£107/MWh +167% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

6.4 Modelling Assumptions

Table 15 provides commentary on the modelling assumptions and uncertainties that specifically relate to an amine capture plant attached to a gas fired power plant. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* report conducted as part of this assignment.

Table 15. Gas Benchmark – Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	MEA post combustion capture on gas power generation has a relatively low level of technical risk compared to other scenarios. However, there is risk associated with assuming that the power plant will be permitted to operate as a base load electricity provider. If the plant is required to operate as a peaking plant to balance non-dispatchable energy sources, such as wind or solar, then asset utilisation will go down and LCOC will increase. Similarly, increases to natural gas prices could impact the economics of gas fired power generation and result in lower asset utilisation.
Input gas composition	See Appendix B	High	Low	Low	If hydrogen was blended into the gas grid the concentration of CO_2 in the flue gas processed by the capture plant would reduce and LCOC would increase. However, if the plant was located upstream of the blending point this would not be an issue.
Overall capital cost	See Table 11	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to capital cost. However, cost uncertainty is low in comparison to other scenarios in this analysis.
Maintenance	See Table 12	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost. However, cost uncertainty is low in comparison to other scenarios in this analysis.
Electricity consumption	See Table 12	High	Low	Low	Electrical energy requirements are relatively well known for MEA capture plants with a defined configuration.
Steam consumption	See Table 12	High	Medium	Medium	Thermal energy requirements are relatively well known for MEA capture plants. However, thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 6.1	High	Medium	Medium	Steam price is based on lost potential revenue from electricity sales. Thermal energy is the single largest operating cost for the plant.
Primary consumables (solvent)	See Table 12	Medium	Medium	High	Solvent use is an important performance parameter and due to the limited number of operational examples there is uncertainty relating to usage rates.
Input gas pre-treatment	See Table 10	High	Medium	Medium	Input gas pre-treatment requirements are less onerous than for the EfW or cement scenarios.
CO_2 conditioning	See Table 10	High	Medium	Medium	The flue gas input gas has a more limited range of contaminants than the EfW or cement scenarios and the amine capture process will absorb some contaminants.

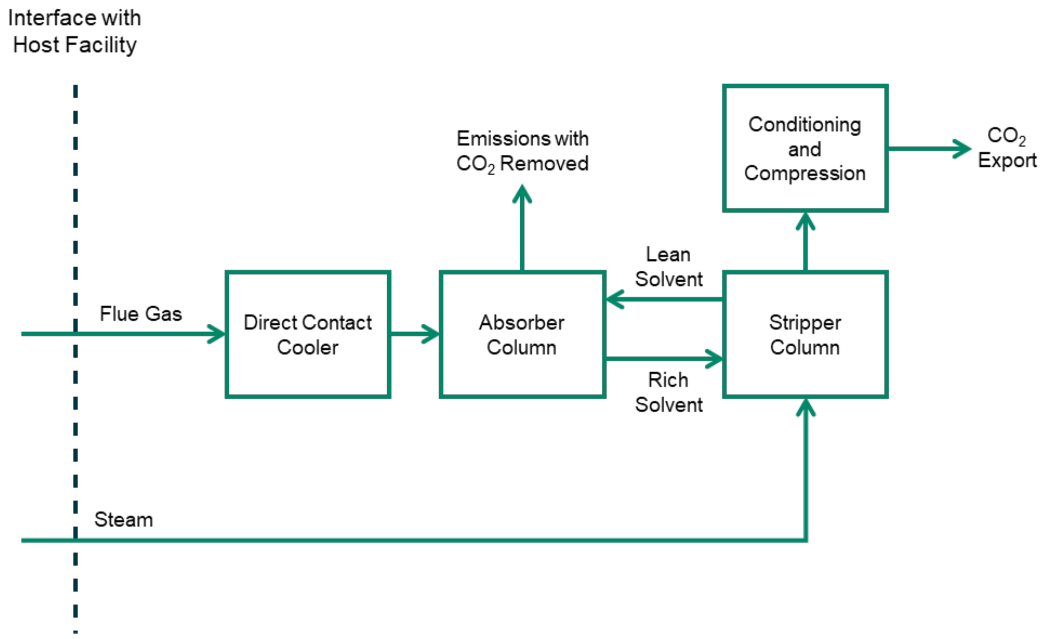
Overall, there is a *medium* level of uncertainty associated with the modelling of this scenario. The results rely on gas fired power generation with CCS being used for base load power supply.

7. Advanced Amine - Gas

7.1 Description of Scenario

This scenario involves a new build combined cycle gas turbine (CCGT) power plant with a gross electrical output of 910 MWe fitted with an advanced amine post combustion capture plant. The scenario is intended to represent how future generations of amine solvent capture plants may develop. The capture concept remains the same as the benchmark, but there are developments in solvent chemistry and across the process. Figure 18 shows a block flow diagram of the process.

Figure 18. Block Diagram – CCGT with advanced amine capture



Several companies are developing advanced amine systems, including Mitshubushi Heavy Industries, Shell, Fluor, Carbon Clean and Aker. Details of the processes are provided in the *Review of Next Generation Technologies* report conducted as part of this study.

The dashed line in Figure 18 represents the interface with the gas fired power plant host facility, as described in the gas fired power generation benchmark. As with the benchmark scenario, the electricity input to the capture plant is not shown explicitly in the diagram but is assumed to be provided by the power plant.

A summary of technical information for the base process and carbon capture plant is presented in Table 16. A diagram of the process containing further information is provided in Appendix A.

Table 16. Advanced Amine – Gas Configuration summary

Item	Description
Base Process Plant	**New build CCGT power plant**
Power output	Single H-class gas turbine with HRSG and condensing steam turbine 910 MW gross electrical output 874 MW net electrical output without carbon capture 788 MW net electrical output with carbon capture
Flue gas output	3,686 tph 5 mol% CO_2
Flue gas treatment	Low NO_X burners SCR to control NO_X SO_X abatement not required from gas combustion Particulate abatement not required from gas combustion
Carbon Capture Plant	**Post Combustion improved amine solvent**
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure Direct contact cooler to reduce temperature
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Steam powered reboiler on stripper column Single stage thermal reclaiming with upstream solvent filter Improved thermal integration of process units relative to benchmark. Basic mechanical vapour recompression included in some systems.
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	Improved amine solvent
CO_2 capture rate	95% of CO_2 emissions from flue gas during normal operation Greenhouse gas emissions from natural gas production are not included
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	100 barg for export pipeline
Mass of CO_2 captured	272 tph (6,527 tpd)
Steam supply	193 MW_{th} from main power plant This steam use represents the overall heat load of the capture plant
Electricity supply	32 MW_e from main power plant

7.1.1 Flue Gas Pre-Treatment

Research and development work has been, and will continue to be, conducted into the development of new amine solvents that are more tolerant to impurities in flue gas. This work involves both formulating new solvents and the development of additives that can be used to enhance the performance of existing solvents. Research in this area is being conducted by suppliers of amine solvent capture systems and a range of academic institutions.

Having a solvent that is more resistant to chemical degradation is valuable in the capture process as it could allow less pre-treatment of the incoming flue gas or require less solvent regeneration and replacement if the same amount of flue gas pre-treatment is applied. If solvent degradation is reduced, this would also be expected to reduce the mass of any harmful degradation products generated.

Despite this, there is evidence that advanced amine solvents may require somewhat stricter limits on input levels of NO_X and SO_X. This is likely due to most advanced amine systems deriving from non-primary amines and having higher specific replacement costs.

In this scenario it has been assumed that the flue gas pre-treatment equipment is the same as in the benchmark scenario as the known input requirements, though stricter, are still met by the same flue gas pre-treatment equipment.

7.1.2 Improved Solvent Performance

A number of improvement areas for advanced amine solvents have been identified, leading to improved process performance. These improvements include reduced volatility, reducing evaporative losses of solvent; increased thermal stability; reducing thermal degradation of solvent; reduced oxidation rate, reducing oxidative degradation of solvent; and reduced thermal regeneration energy, reducing energy consumption of the absorption and desorption process cycle. These factors result in significant savings on both solvent consumption and energy consumption.

These advances in solvent performance come at the cost of an increased solvent price, as required for a tailored, more complex, and most often proprietary chemical when compared to the standard generic amine of the benchmark.

After accounting for both a reduction in solvent use and increase in solvent price, an overall reduction in solvent cost is expected for the advanced amine process. Based on vendor provided information a significant reduction in solvent use has been assumed and reduced solvent regeneration requirements contribute to lower energy consumption. The generation of solvent waste products is likewise anticipated to reduce.

7.1.3 Energy Consumption

Different strategies can be used to improve the energy performance of amine capture plants. An overview of options is provided below.

Solvent improvements – Changes to the solvent chemistry can allow reductions in energy use at the capture plant. Areas of development include decreasing the heat of reaction or increasing the CO_2 absorption capacity of the solvent. Other factors, such as solvent viscosity and associated pumping costs, will also impact energy use at the plant.

The impact of changes to solvent chemistry on energy performance should not be considered in isolation. If a new solvent formulation allows reduced energy use, but costs more to purchase or is more susceptible to degradation, then overall it may be a less desirable solvent for the application being considered.

Thermal integration – Energy savings can be achieved through improvements to the design of thermal integration systems at the capture plant. This could include heat recovery from equipment not directly related to the capture process, such as CO_2 compression. Mechanical vapour recompression systems can also be used to reduce steam demand, although the additional electrical consumption of this equipment must be considered.

While performance improvements are achieved using thermal integration, there may be trade-offs between reduced energy consumption and equipment cost, reliability, ease of operation and operational flexibility. Competing priorities require to be balanced in the design of thermal integration systems.

Changes to process conditions - Changes to operating conditions such as temperatures or pressures in the capture plant can provide reductions in energy use. For example, increasing temperature and pressure in the stripping column will reduce subsequent CO_2 compression costs. As with other energy saving measures, changes to process conditions may compromise other aspects of plant performance. Increased temperatures in the stripper column will increase thermal degradation of the solvent.

Each supplier of advanced amine solvent technology will use a combination of the above energy saving techniques. As knowledge and experience is gained in applying the equipment to different applications, incremental improvements in the overall performance of amine capture plants are anticipated.

In this scenario a 34% reduction in steam consumption and a 22% reduction in electricity use has been assumed relative to the benchmark MEA scenario. These figures are based on interpretation of vendor information on what the technology is likely to achieve in the future. The anticipated performance of advanced amine systems varies between technologies and literature sources, with some being less optimistic than assumed in this scenario.

7.1.4 Current Demonstration Status

Like any other technology, amine capture technologies develop through a process of incremental improvements. While the definition of when an amine capture technology becomes “Advanced” has not been fixed in this study, the technoeconomic assessment for this scenario is based on the performance of amine solvent systems that is anticipated to be available in the market in the next 5-10 years.

Unlike the other next-generation technologies in this study, amine capture plants of comparable scale to the scenarios being analysed have been constructed and operated. Examples include Fluor’s 320-350 tpd Bellingham Gas Power Plant in Massachusetts, USA [11], MHI’s 4,700 tpd Petra Nova coal-fired power plant in Texas, USA [13] and Shell’s 3,000 tpd plant at Saskpower’s Boundary Dam coal-fired power station in Saskatchewan, Canada [14].

While operational issues have been experienced at these projects, the construction and operation of full-scale post combustion projects will have provided valuable information on how subsequent projects should be constructed and operated, although much of this learning is not in the public domain.

7.1.5 Technology Development

Key areas for technology development in amine capture systems include:

- Plant reliability
- Improved management of existing solvents and additives
- Improved solvents and additives – allowing reductions in operational cost, energy use and safety and environmental hazards
- Reduced energy use – thermal and electrical
- Optimised integration with the base process plant
- Improvements in operational flexibility
- Reduced equipment costs
- Modularisation and standardisation of designs

Collectively, incremental improvements in the above areas will improve the overall performance of amine capture technology.

Hazards

The hazards present in an advanced amine capture plant will be similar to those in the benchmark amine case.

Some advanced amine plants will use solvents based on secondary or tertiary amines. These categories of amines have more potential to form degradation products containing nitrosamines. These compounds are of particular concern as they can be toxic, mutagenic, and carcinogenic. It is important to understand the formation, nature and management of degradation products generated by amine solvents. As amine capture plants are deployed, an associated regulatory framework will develop. Work has recently been completed to develop an evidence base for the definition of Best Available Techniques (BAT) for amine solvent post-combustion capture plants for gas-fired power generation [15].

Maintenance

The overall process concept in an advanced amine plant is the same as in the benchmark case, so maintenance requirements will be similar. However, improvements in relation to plant maintenance are possible in several areas.

- **Operator feedback** – over time, feedback from owners and operators of amine capture equipment should help improve the design of equipment to allow maintenance costs to be reduced. For solvent-based capture technology, this process has already progressed further than for other next generation technologies.
- **Maintenance management systems –** there continues to be advances in maintenance management systems, with simulation software allowing the impact of different operating strategies and conditions to be more accurately assessed.

- **Material selection and development** – materials science and construction techniques continue to evolve potential reductions in maintenance requirements.
- **Skills development –** some items of equipment in the capture plants require specialist skills during maintenance. Establishment of a carbon capture industry in the UK will increase the number of individuals with the required skills.

7.2 Cost Summary

Table 17 and Table 18 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 17. Advanced Amine – Gas Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£47.1m
Capture Technology	£96.3m
CO_2 conditioning	£3.7m
CO_2 compression	£32.9m
Auxiliary Systems	£67.7m
Civil works	£57.6m
Total EPC	**£305.2m**
Project Development Costs	
Land Requirements	£1.0m
Utility & Infrastructure Connections	£3.1m
Consultancy	£3.1m
Planning & Other Regulatory	£6.1m
Developer’s Costs	£21.4m
Start-Up & Commissioning	£15.3m
Total Project Development	**£49.8m**
Total Capital Cost	
Total Capital Cost	£355.0m
Contingency	10%
Grand Total CAPEX	**£390.5m**

Lessons learned, standardisation of designs and modularisation may help to reduce costs for advance amine systems. However, these reductions may be balanced by the increased costs of thermal integration systems and equipment, and redundancy and design modifications required to allow consistent high availability operation. Overall, capital costs are anticipated to be similar to current generation amine systems.

Table 18. Advanced Amine – Gas Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£1.4m
Administration	£5.9m
Maintenance	£9.8m
Total Fixed OPEX	**£17.0m**
Variable Costs	
Electricity	£16.4m
Steam supply	£23.3m
Solvent	£0.5m
Other chemicals and consumables	£1.8m
Wastes	£2.0m
Plant auxiliary	£0.3m
Total Variable OPEX	**£44.3m**
Total Operating Cost	
Total Operating Cost	£61.3m
Contingency	10%
Grand Total OPEX	**£67.4m**

Advances in solvent performance and energy efficiency are likely to lead to reduced operating expenditure on solvent, electricity, and steam over less advanced amine systems.

7.3 Key Outputs

Table 19 contains a summary of the values relating to the LCOC.

Table 19. Advanced Amine – Gas Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	2.0 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	50.6 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	18.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£390.5m	
Average total annual OPEX	£67.4m	
Lifetime cost	£2,076.4m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£983.6m	Adjusted lifetime cost value based on discount rate.
LCOC	**£52/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 19.

Figure 19. Advanced Amine – Gas LCOC

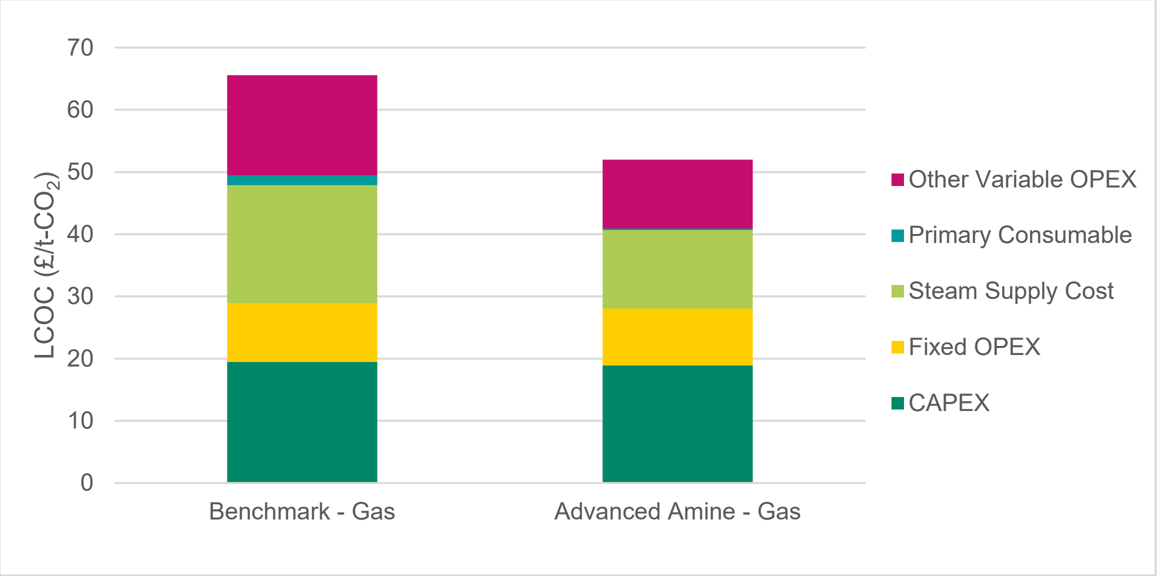


Figure 19 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the Benchmark and 95% for the Advanced Amine.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The advanced amine scenario shows a reduced LCOC relative to the benchmark case. The cost reduction is primarily due to reduced energy consumption.

Table 20 contains a summary of the values relating to the impact of adding carbon capture on product cost.

Table 20. Advanced Amine – Gas Impact on product cost

Item	Value	Comment
Product produced	Electricity	
Lifetime electricity produced	146,613 GWh	Net production with capture
Lifetime CO_2 captured	50.6 Mt	
LCOC	£52/t	From calculations above
Lifetime CO_2 residual emissions	2.7 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£37.8m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64/MWh	Price includes no additional cost to the host plant for emission of CO_2 to the atmosphere.
Product cost with impact of capture only	£82/MWh +£18/MWh +28% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£70/MWh +£6/MWh +10% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£88/MWh +£24/MWh +38% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£171/MWh +£107/MWh +167% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

7.4 Modelling Assumptions

Table 21 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 21. Advanced Amine – Gas Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	Increased operational experience should reduce the availability uncertainty associated with advanced amine capture technology. Furthermore, advanced amine systems are being developed by large companies with the ability to offer meaningful guarantees in relation to plant performance. There is risk associated with assuming that the power plant will be permitted to operate as a base load electricity provider.
Input gas composition	See Appendix B	High	Low	Low	If hydrogen is blended into the gas grid, the concentration of CO_2 in the flue gas processed by the capture plant will reduce and LCOC will increase. However, if the plant were located upstream of the blending point this would not be an issue.
Overall capital cost	See Table 17	Medium	Low	Low	Technologies developed based on incremental improvements have a lower level of cost uncertainty than those using new concepts.
Maintenance	See Table 18	Medium	Low	Low	Technologies developed based on incremental improvements have a lower level of cost uncertainty than those using new concepts.
Electricity consumption	See Table 18	High	Low	Low	Electrical energy requirements are relatively well known for advanced amine capture plants.
Steam consumption	See Table 18	Medium	Medium	High	Thermal energy requirements are relatively well known for advanced amine capture plants. However, thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 6.1.2	High	Medium	Medium	Steam price is based on lost revenue from electricity sales. Thermal energy is the single largest operating cost for the plant.
Primary consumables (solvent)	See Table 18	Medium	Medium	High	Solvent use is an important performance parameter and due to the limited number of operational examples, there is some uncertainty relating to usage rates. Significant reduction in solvent expenditure has been assumed relative to the benchmark.
Input gas pre-treatment	See Table 16	High	Medium	Medium	The flue gas input gas has a more limited range of contaminants than the EfW or cement scenarios.
CO_2 conditioning	See Table 16	High	Medium	Medium	The flue gas input gas has a more limited range of contaminants than the EfW or cement scenarios and the amine capture process will absorb most contaminants.

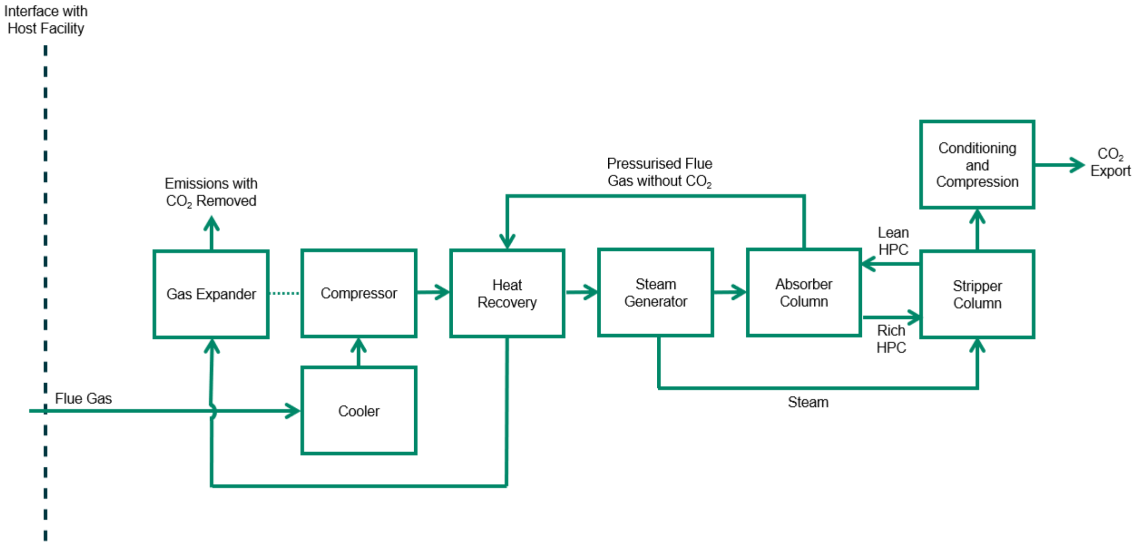
Overall, there is a *medium* level of uncertainty associated with the modelling of this scenario. If more plants are built, incremental improvements in amine capture technology can be expected. The generation of harmful solvent degradation products will need to be better understood and managed.

8. Hot Potassium Carbonate – Gas

8.1 Description of Scenario

This scenario involves a new build gas power plant with hot potassium carbonate (HPC) solvent capture and CO2 Capsol's heat recovery process. Figure 20 shows a process block diagram of the process, with the dashed line representing the interface between the capture plant and the host power plant.

Figure 20. Block Diagram – CO2 Capsol on Gas Power



One important process difference in comparison to the benchmark case is that the system uses pressurised flue gas in the absorber column. The solvent is then regenerated by passing it to a stripper column where the pressure is reduced and the CO_2 is released. This alternative method of solvent regeneration means that electrical energy requirements are increased (to compress the incoming flue gas) and thermal energy requirements are decreased. CO2 Capsol offer a zero thermal energy input option where all thermal energy required for the stripper column is recovered from the process after the flue gas compression.

The CO2 Capsol process has following potential advantages:

- HPC is relatively low cost and less hazardous than other solvents, although it should be noted that some HPC processes use potentially harmful chemicals such as amines or piperazine to aid solvent performance. It is understood that the CO2 Capsol process does not.
- Energy for the system can be provided fully, or partly in the form of electricity. Steam for the stripper is generated within the capture plant so there is a reduced requirement for imported thermal energy. This may be an advantage in relation to overcoming integration challenges with the host facility. In the modelled scenario only a small amount of steam is imported from the host plant for use in CO_2 conditioning.

A summary of technical information for the base process and carbon capture plant is presented in Table 22. A diagram of the capture process containing further information is provided in Appendix A.

Table 22. Hot Potassium Carbonate – Gas Configuration summary

Item	Description
Base Process Plant	**New build CCGT power plant**
Power output	Single H-class gas turbine with HRSG and condensing steam turbine 910 MW gross electrical output 874 MW net electrical output without carbon capture 728 MW net electrical output with carbon capture
Flue gas output	3,686 tph 5 mol% CO_2
Flue gas treatment	Low NO_X burners SCR to control NO_X SO_X abatement not required from gas combustion Particulate abatement not required from gas combustion
Carbon Capture Plant	**Post Combustion Capture using CO2 Capsol process**
Additional flue gas pre-treatment for capture plant	Cooler to reduce temperature Flue gas compressor (to 9 bara)
Capture	Packed bed pressurised absorber column Gas expander to recover energy from absorber column discharge Packed bed stripper column Lean vapour flash compressor discharging to stripper column Flash steam compressor discharging to stripper column Steam powered reboiler on stripper column Solvent reclaiming – details unspecified
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	Hot potassium carbonate (HPC) solution
CO_2 capture level	90% of CO_2 emissions from flue gas during normal operation Achieving a higher capture level with this technology when capturing CO_2 from gas power generation flue gas would require additional compression of the flue gas and increase costs.
Operational hours	7,446 hours/year (8,760 hours * 85%)
CO_2 export pressure	100 barg for export pipeline
Mass of CO_2 captured	258 tph (6,184 tpd)
Steam supply	4 MW from main power plant for use in CO_2 conditioning. Steam for the stripper column is produced within capture plant using heat recovered from flue gas compressor.
Electricity supply	137 MW from main power plant

8.1.1 Flue Gas Pre-Treatment

In this scenario, the flue gas must be cooled and compressed to around 9 bara prior to enter the absorber column. This requires a large, high-power compressor unit. The process diagram provided by CO2 Capsol indicates that this compressor is directly coupled to a motor and a gas expander to recover energy from the pressurised exhaust of the absorber column.

This process stage would require a specialised compressor/expander item of equipment. The availability and costs of this piece of equipment at the required scale would need to be investigated during the development of a project. If a single compressor/expander unit was difficult to procure, other equipment configurations could be used for compressing the flue gas to the required pressure. However, this may have cost or energy consumption implications.

As with the amine solvent in the benchmark case the HPC solvent will form heat stable salts and degrade when exposed to contaminants such SO_X and NO_X. No additional treatment has been assumed in this scenario to remove flue gas contaminants prior to entry into the capture plant. However, it should be noted that information was not available on degradation rates for HPC solvent when used on gas turbine flue gas. Solvent testing under representative conditions would reduce uncertainty in relation to solvent management costs and the optimum level of flue gas pre-treatment required.

8.1.2 Energy Consumption

There is no requirement for large amounts of steam to be extracted from the main power plant in this scenario. Only a small amount of imported steam is required for CO_2 conditioning. This could be an advantage in relation to steam turbine selection. It could be a significant advantage in relation to retrofit projects where it was difficult to extract the required volume of steam due to the design of the existing steam turbine.

The bulk of the energy supply to the plant is in the form of electricity and is used to operate the flue gas compressor and mechanical vapour recompression systems. Thermal energy is then recovered and exchanged at various points inside the CO2 Capsol process. There is a moderate degree of complexity associated with the energy integration systems at the plant. For example, after cooling and compression, the flue gases pass through a further three heat exchangers prior to entry into the absorber column.

Efficiency or cost savings may be possible if a limited quantity of additional thermal energy was provided to the process by the gas power plant to reduce reliance on heat recovery systems included in the design.

When comparing energy consumption figures across capture technologies it is important to remember that more than one unit of thermal energy can be extracted from a steam turbine for every unit of electrical energy sacrificed. The ratio of useful heat exported to the reduction in electrical energy output from a steam turbine is referred to at the Z ratio and will vary between different steam turbines. Direct comparison of steam and electrical power consumption figures is generally not appropriate.

8.1.3 Current Demonstration Status

HPC has been used commercially as a solvent in gas processing applications. However, it has not been used for post combustion CO_2 capture.

There have been three pilot projects using CO_2 Capsol process for post combustion capture, all at scales of less than 2 tpd. Two of the projects were based at a biomass-fired power plants and one at a coal-fired power plant. These projects may not have included all of CO_2 Capsol's proposed energy integration system due to their limited scale.

A study was carried out in 2020 assessing the feasibility and economics of using the CO_2 Capsol process on an EfW plant at a capture scale of 300 to 500 ktpa [16]. There are also proposals for deployment at Stockholm Exergi's biomass-fired CHP plant in Värtaverket, Sweden at a capture scale of up to 800 ktpa of CO_2 [17].

As far as we are aware, there has not yet been any testing of the CO_2 Capsol process for post combustion capture on the flue gases from a gas turbine power plant.

8.1.4 Technology Development

Measures that could be taken in relation to applying the CO2 Capsol technology to gas power flue gases include:

- Testing the solvent on representative input flue gas to validate performance, understand degradation characteristics and understand solvent management requirements.
- Construction of an intermediate scale demonstration project to validate costs, reliability, and energy performance predictions. To prove that energy performance based on modelled scenarios can be achieved in a working plant, the configuration of any demonstration facility would need to match the modelled configuration and include all thermal integration design features. In addition, the scale would need to be sufficient so that mass and heat transfer characteristics of the demonstration plant were representative of a larger commercial facility.

Due to the similarities between the processes, many of the areas for technology development in non-amine solvent capture systems are the same as those for amine systems on gas power plants, as described in Section 6.1.4.

The modelled scenario captures 90% of the CO_2 from the incoming flue gas. Achieving a higher CO_2 capture level in a combined cycle gas power generation application, with low concentrations of CO_2 in the flue gas, would increase the cost of capture. The capture level required by future commercial plants may impact the suitability of this technology arrangement in this application.

CO2 Capsol is also developing a capture solution for open cycle gas power plants. In an open cycle gas power plant there is no heat recovery steam generator on the gas turbine exhaust and no steam turbine generating additional power. Open cycle gas power plants have a lower efficiency than combined cycle plants but have other advantages including faster start-up and lower capital cost. They are used in different applications including providing peaking electrical power and in some industrial settings.

When CO2 Capsol's system is applied to an open cycle gas power plant, a surplus of electricity can be generated by the capture plant and a higher capture level (95%+) can be achieved. The system uses CO2 Capsol's patented heat recuperation arrangement and does not require external steam supply from the host plant. The system has the potential to increase the efficiency of an open cycle power plant without adding a steam cycle. This may have advantages in relation to cost and plant footprint in addition to the benefits of a less hazardous solvent.

Hazards

The hazards present in a HPC solvent capture plant will be similar to those in the benchmark amine case. However, the process is different, with different operating pressures and temperatures. As with all process plants, structured hazard identification and mitigation measures would be required throughout the design and development of the process.

Replacement of an amine-based solvent with HPC will reduce the hazard associated with the solvent. Potassium carbonate is used in the food industry and poses lower risk towards the environment and people. Understanding and management of the hazards associated with solvent degradation products, or contaminants collected by the solvent, will still be required at a gas power facility using HPC.

Maintenance

The overall process concept in a non-amine capture plant is like the benchmark amine cases, so maintenance requirements will be similar. If a solvent is less corrosive or has lower levels of degradation this may result in reduced maintenance requirements.

Processes that use more complex energy integration systems are likely to have increased maintenance requirements because of additional equipment. The CO2 Capsol process contains a large size compressor and expander, mechanical vapor recompression systems and a greater number of heat recovery heat exchangers than other solvent based capture processes.

The CO2 Capsol energy integration process is different from other solvent capture processes in several areas, and it has not been demonstrated at scale. Construction and operation of a demonstration facility would reduce uncertainty in relation to availability, capital, and maintenance costs.

General improvements in relation to plant maintenance for solvent capture systems are possible in several areas; details are provided in Section 6.1.4.

8.2 Cost Summary

Table 23 and Table 24 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 23. Hot Potassium Carbonate – Gas Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£30.3m
Capture Technology	£115.9m
CO_2 conditioning	£3.5m
CO_2 compression	£31.7
Auxiliary Systems	£57.9m
Civil works	£57.6m
Total EPC	**£296.8m**
Project Development Costs	
Land Requirements	£0.3m
Utility & Infrastructure Connections	£3.0m
Consultancy	£3.0m
Planning & Other Regulatory	£5.9m
Developer’s Costs	£20.8m
Start-Up & Commissioning	£14.8m
Total Project Development	**£47.8m**
Total Capital Cost	
Total Capital Cost	£344.7m
Contingency	10%
Grand Total CAPEX	**£379.1m**

Table 24. Hot Potassium Carbonate – Gas Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£1.4m
Administration and other overheads	£5.7m
Maintenance	£9.5m
Total Fixed OPEX	**£16.5m**
Variable Costs	
Electricity	£69.5m
Steam supply	£0.5m
Solvent	£0.2m
Other chemicals and consumables	£0.0m
Wastes	£1.8m
Plant auxiliary	£0.3m
Total Variable OPEX	**£72.3m**
Total Operating Cost	
Total Operating Cost	£88.8m
Contingency	10%
Grand Total OPEX	**£97.7m**

8.3 Key Outputs

Table 25 contains a summary of values relating to the LCOC.

Table 25. Hot Potassium Carbonate – Gas Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	1.8 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	48.0 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	17.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£379.1m	
Average total annual OPEX	£97.7m	
Lifetime cost	£2,822.4m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£1,253.3m	Adjusted lifetime cost value based on discount rate.
LCOC	**£70/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 21.

Figure 21. Hot Potassium Carbonate – Gas LCOC

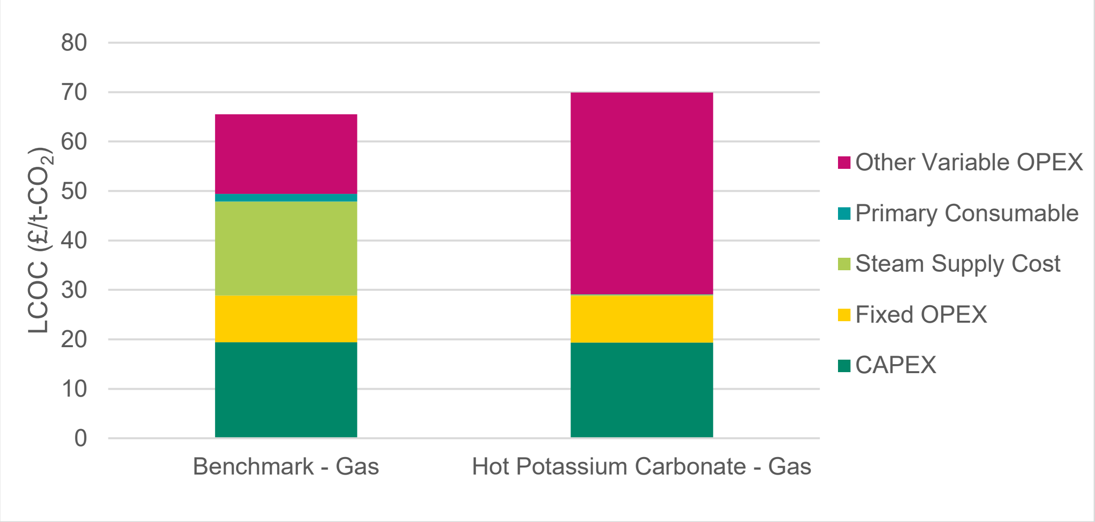


Figure 21 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the Benchmark and 90% for the Hot Potassium Carbonate scenario.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The hot potassium carbonate scenario shows an increased LCOC relative to the benchmark case. When this technology is applied to an EfW plant later in the report, a reduction in LCOC is observed relative to the EfW benchmark. This is due to the higher concentration of CO_2 in the EfW flue gas, which is of greater benefit to this technology, and the higher assumed cost of thermal energy in the EfW scenario.

The hot potassium carbonate technology uses mainly electricity rather than steam. This is most advantageous in situations where access to thermal energy is restricted or expensive. The technology could also be applied to the cement sector where low carbon thermal energy may not be readily available.

Table 26 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 26. Hot Potassium Carbonate – Gas Impact on product cost

Item	Value	Comment
Product produced	Electricity	
Lifetime electricity produced	135,471 GWh	Net production with capture
Lifetime CO_2 captured	48 Mt	
LCOC	£70/t	From calculations above
Lifetime CO_2 residual emissions	5.3 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£73.7m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64/MWh	Price includes no additional cost to the host plant for emission of CO_2 to the atmosphere.
Product cost with impact of capture only	£89/MWh +£25/MWh +39% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£77/MWh +£13/MWh +20% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£102/MWh +£38/MWh +59% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£171/MWh +£107/MWh +167% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

8.4 Modelling Assumptions

Table 27 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 27. Hot Potassium Carbonate – Gas Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The capture concept has similarities to amine solvent capture, which is relatively well understood. However, there is currently no intermediate scale demonstration plant and there is complexity to the energy integrations systems included.
Input gas composition	See Appendix B	High	Low	Low	If hydrogen was blended into the gas grid the concentration of CO_2 in the flue gas processed by the capture plant would reduce and LCOC would increase and capture level may drop. However, if the plant was located upstream of the blending point this would not be an issue.
Overall capital cost	See Table 23	Medium	Medium	High	The lack of an intermediate scale demonstration plant using a comparable energy integration system increases cost uncertainty. Reduced thermal energy demand should make integration with the host plant simpler.
Maintenance	See Table 24	Medium	Low	Low	It is anticipated that maintenance requirements will be similar to other solvent based systems. When a project is being developed it will be important to understand the maintenance requirements for the compressors across the plant.
Electricity consumption	See Table 24	Medium	Medium	High	Electrical energy is the single largest operating cost, so any changes may impact LCOC.
Steam consumption	See Table 24	High	Low	Low	Only small amounts of steam used for CO_2 conditioning.
Steam price	See Section 6.1.2	High	Low	Low	Only small amounts of steam used for CO_2 conditioning.
Primary consumables (solvent)	See Table 24	Medium	Medium	High	Solvent may degrade faster than expected. This uncertainty can be reduced through solvent testing under representative conditions.
Input gas pre-treatment	See Table 22	Medium	Low	Low	The flue gas input gas has a more limited range of contaminants than the EfW or cement scenarios.
CO_2 conditioning	See Table 22	High	Medium	Medium	The flue gas input gas has a more limited range of contaminants than the EfW or cement scenarios and the solvent capture process will absorb most contaminants.

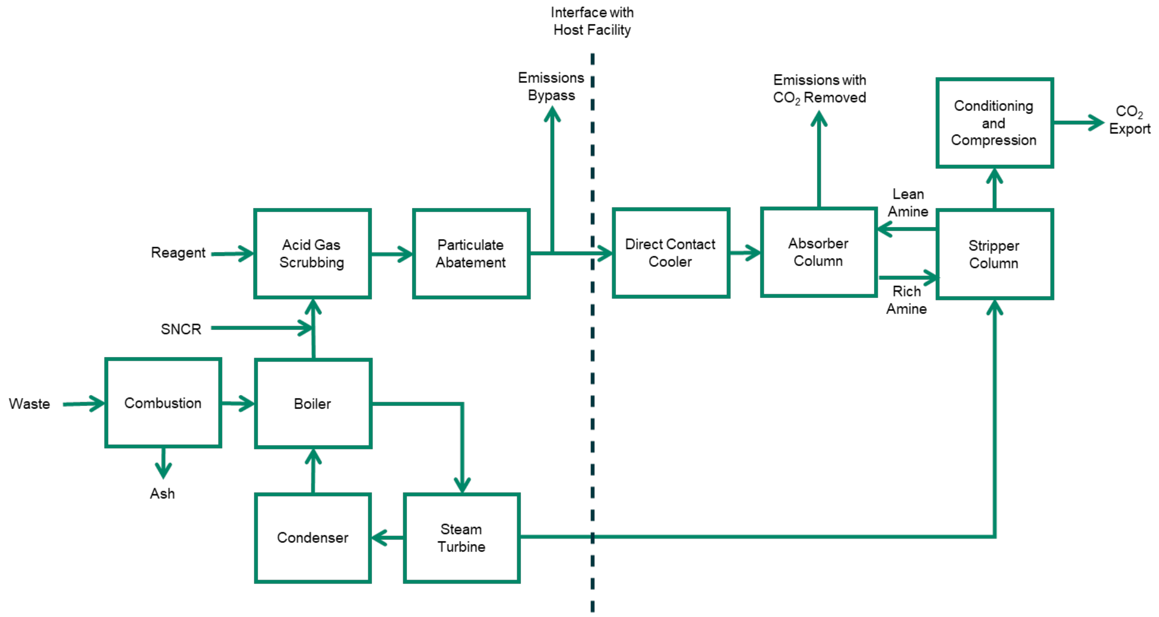
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. A less hazardous, non-proprietary, solvent is an advantage and the use of electrical energy rather than thermal could aid integration with the host plant. However, the energy integration system within the capture plant remains to be demonstrated at scale and multiple scale-up steps may be advisable.

9. EfW Benchmark

9.1 Description of Scenario

This benchmark scenario involves retrofit of an existing 350,000 tpa of waste EfW plant fitted with a post combustion amine-based carbon capture plant to create negative emissions waste treatment. While this scenario relates to EfW, the equipment required, and results obtained are likely to be similar for a biomass power plant of comparable scale. Figure 22 shows a block flow diagram of the process, with the dotted line representing the interface between the existing EfW plant and new capture plant.

Figure 22. Block Diagram – EfW with amine capture



Although not shown explicitly in this diagram, it is assumed that electricity consumed by the capture plant will be provided by the power plant.

EfW plants treat residual waste after recyclable material has been removed and allow further recovery of materials including metals and bottom ash for use as an aggregate. The residual waste input contains carbon of biological origin. Therefore, the addition of capture technology to an EfW plant allows for negative emissions waste treatment. If used appropriately the technology has the potential to address several environmental issues.

The benchmark scenario uses 35% w/w MEA solution as a solvent. Performance information is readily available for this solvent, and the solvent can be sourced from a variety of suppliers. It has been adopted as the benchmark technology for this study as it provides robust, known performance that can be applied as a consistent reference technology for all next generation scenarios assessed.

Leading suppliers of amine solvent capture plants will generally offer a proprietary amine blend solvent with claims of improved performance. Assessing the relative performance of current proprietary amines is outside the scope of this study. However, the study includes advanced amine scenarios for EfW and gas power generation based on process and solvent developments anticipated to be available in the 2030-35 timescales.

A summary of technical information for the base process and carbon capture plant is presented in Table 28.

Table 28. EfW Benchmark - Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture (based on typical performance of an EfW plant in the UK) 9 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion MEA solvent**
Additional flue gas pre-treatment for capture plant	Potential limited modifications to existing acid-gas abatement system to reduce SO_X Flue gas blower to increase pressure and allow admission into downstream process units Direct contact cooler to reduce temperature, with additional caustic treatment for SO_X reduction
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Basic thermal integration of stripper and absorber columns Steam powered reboiler on stripper column Single stage thermal reclaiming
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	35% w/w Monoethanolamine (MEA)
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	42 tph (1000 tpd)
Steam supply	46 MW from EfW plant This steam use represents the overall heat load of the capture plant
Electricity supply	7 MW from EfW plant

9.1.1 Flue Gas Pre-treatment

For capture plants retrofitted to existing EfW plants, it is important that the composition of the flue gas is understood and the interface with the existing plant is appropriately designed. The level of additional treatment required will be site specific and depend on factors including the feedstock used, the emissions abatement system already in place and the requirements of the proposed capture technology.

For contaminants including particulates, heavy metals and volatile organic compounds, it has been assumed that the abatement measures included in the host process plant will be relied upon. The long-term impact of trace contaminants on solvent performance is an area of uncertainty and the subject of ongoing research.

Two important parameters to consider in relation to flue gas pre-treatment are NO_X and SO_X. These are discussed in more detail below.

Oxides of Nitrogen – NO_X

Oxides of nitrogen react with amine solvent and cause the solvent to degrade. Of particular concern is NO_2, which reacts to form nitric acid and subsequently heat stable salts, and nitrosamines if secondary amines are present. It has been suggested that the concentration of NO_2 in flue gas should be restricted to approximately 20 ppmv at 6% O_2 for economic post-combustion capture using amine [18]. Converting to the reference O_2 concentration for EfW flue gases gives a guidance figure of 13 ppmv at 11% O_2, or 27 mg/Nm^3.

The reference flue gas for the EfW benchmark has a NO_X concentration of 150 mg/Nm^3. If 10% [19] of the NO_X is NO_2 this gives a NO_2 concentration of 15 mg/Nm^3. On this basis no further NO_X control would be needed prior to an amine capture plant based on this input gas specification. However, it is noted that some projects that are developing carbon capture for EfW plants assume that additional SCR will be installed as part of the capture plant retrofit, based on specific flue gas conditions and proprietary solvent performance.

Oxides of Sulphur - SO_X

Oxides of sulphur also react with amine solvent causing it to form heat stable salts. It has been suggested that the concentration of SO_2 in flue gas should be restricted to approximately 10 ppmv at 6%O_2 for economic post-combustion capture using amine [18]. Converting to the reference O_2 concentration for EfW flue gases gives a guidance figure of 7ppmv at 11%O_2, or 20mg/Nm^3.

The reference flue gas for the EfW benchmark has a SO_X concentration of 20 mg/Nm^3. If 95% [20] of the SO_X is SO_2, this gives a SO_2 concentration of 19 mg/Nm^3. On this basis no further SO_X control would be needed prior to an amine capture plant based on this input gas specification. If reduced SO_X levels are required, it may be possible to meet them by making changes to the operation of the acid gas abatement system.

9.1.2 Thermal Energy

If a carbon capture plant is being retrofitted to an existing EfW facility, a certain amount of steam will be available from the existing EfW plant with limited modifications required. The mass of steam that is easily available will depend on the design of the steam turbine and steam system installed. If sufficient steam is readily available, then the cost of steam would be proportional to the reduction in electrical output that results from extracting steam from the turbine. This was the assumption made for cost of steam in the gas fired power plant scenarios.

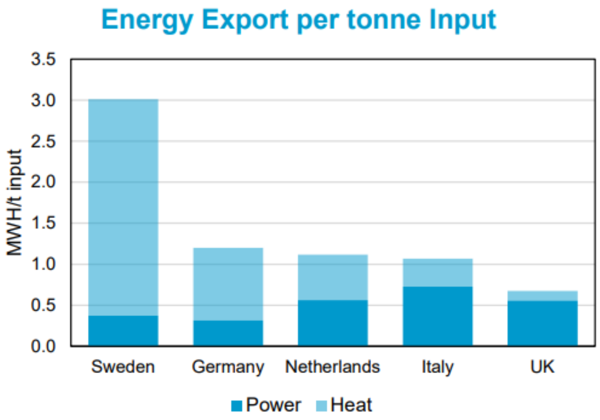
The capture plant requires a significant thermal energy input relative to the total energy flow in the steam cycle of the host EfW plant. At many facilities it may not be possible to easily extract the required volume of steam from existing equipment due to limitations in the design of the installed steam turbine. For example, the diameter of extraction nozzles. Even if the steam system at an existing EfW plant could provide the required volume of steam with limited modifications, then there may be efficiency or operational flexibility penalties associated with extracting this volume of steam.

For the purposes of this study the unit cost for steam in any given year of the model has been assumed to be the wholesale electricity price for that year divided by 2 for the EfW scenarios. This value for the unit cost of steam includes contributions from both capital and operational costs associated with providing the steam. It is based on the value of lost electrical generation plus a nominal uplift to account for the fact that extensive steam system modifications could be required, and efficiency or operational flexibility penalties could occur depending on how the existing steam system is modified. The actual cost of thermal energy provision will vary between sites and there may be instances when plants are able to access steam with a lower unit cost than that assumed. When carbon capture projects are being investigated at specific EfW sites, the provision of thermal energy to the capture plant should be considered at an early stage of the design process.

EfW plants may also need to consider the provision of thermal energy to existing, or proposed future, district heating networks. Supply of heat to a district heating network is a highly effective and relatively low-tech way of increasing the efficiency of an unabated EfW plant. The export of heat from EfWs decreases CO_2 emissions per unit of energy recovered and should be encouraged for both existing and proposed new EfW plants. New-build EfW plants should seek to be co-located with industrial heat users where possible.

In the UK, EfW's predominantly export electricity, while in other European markets energy is exported through a mixture of electricity, hot water and steam, as shown in Figure 23.

Figure 23. Energy Export from EfWs [21]



The ability of a capture plant and a district heating network to both be served by a particular EfW plant will depend on a variety of factors and will need to be assessed on a case-by-case basis. In many cases both could be served, and if a heat customer can use medium or low-grade heat, then there may be opportunities to use the heat rejected by the carbon capture plant.

None of the scenarios in this study use steam powered drives to operate major items of equipment such as compressors or blowers. This is an option that projects may wish to consider during the engineering design and optioneering phase of project development.

9.1.3 Current Demonstration Status

Examples of carbon capture on existing EfW facilities are limited. However, there is a recognition of the importance of the technology in the sector due to the limited number of other options for decarbonisation of residual waste treatment.

A capture plant with a capacity of around 3.3 ktpa of CO_2 has been in operation since 2016 at an MSW-fired EfW plant in Saga City, Japan [22]. As well as this, AVR's EfW facility in Duiven, the Netherlands, has been capturing up to 60 ktpa of CO_2 from its process since mid-2019 [23].

In Norway, a carbon capture plant is under development at the Klemetsrud EfW facility. This was approved following the success of a pilot plant at the same facility in 2011. The new plant will capture around 350 ktpa of CO_2 [22].

A carbon capture system with a capacity of 100 ktpa of CO_2 is to be provided by Aker Solutions on the Twence EfW site in the Netherlands. The plant will use a modular design and is anticipated to commence operation by the end of 2023 [24].

Viridor have recently announced plans to install carbon capture plants on five of their EfW sites across the UK. Once completed it is expected that sites, along with an additional two planned CCUS plants, will capture 1500 ktpa of CO_2. These sites will be spread out across Scotland, England and Wales [25].

9.1.4 Technology Development

Amine-based post combustion capture technology has been constructed in the power sector at a scale beyond what is required for EfW applications, so scale-up is not required. Areas for technology development in relation to the application of the technology in the EfW sector are described below.

- Increased understanding of the impact of flue gas contaminants on long term solvent performance. This may allow improvements in solvent chemistry and solvent management to be made and will inform choices relating to flue gas pre-treatment equipment. Understanding of the impact of feedstock variations, seasonally and between sites, could also be improved.
- Demonstration of long-term reliable operation to reduce cost and performance uncertainty and build investor confidence.
- Standardisation of designs and improving construction techniques to allow cost reductions.

Hazards

As for the gas power generation benchmark, the main new hazards of this technology are the transport and storage of CO_2, and the release of solvents and or potentially harmful solvent degradation products into the environment. Mitigation measures are available to reduce the risk of harm resulting from these hazards. The presence of additional contaminants in the EfW flue gas has the potential to impact the generation of solvent degradation products and will need to be considered in relation to the development of the technology and selection of flue gas treatment equipment.

For the EfW sector any change to the emissions from the plants has the potential to impact public perception of the technology. We would expect that reducing CO_2 emissions using capture technology to be viewed positively. However, the introduction of any new potentially harmful emissions, such as amine degradation products, risks inviting negative attention, justified or otherwise, from individuals who are opposed to EfW.

Maintenance

Maintenance requirements for amine-based post combustion capture in a gas fired power generation application are described in Section 6.1.4. Requirements when the technology is applied to the EfW sector will be similar.

For EfW plants there will be additional maintenance requirements relating to the pre-treatment equipment for the incoming flue gas. There may also be additional maintenance associated with modifications made to allow the capture plant to interface with the existing EfW plant. This will be site specific but could include maintaining modifications to the steam system or emissions abatement equipment. If a capture plant is to be retrofitted to an existing EfW any changes to the maintenance requirements for the main process plant should be considered during the design process.

9.2 Cost Summary

Table 29 and Table 30 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 29. EfW Benchmark - Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£2.8m
Capture Technology	£18.7m
Conditioning	£0.9m
Compression	£2.9m
Auxiliary Systems	£36.1m
Civil works	£14.4m
Total EPC	**£75.8m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.8m
Consultancy	£0.8m
Planning & Other Regulatory	£1.5m
Developer’s Costs	£5.3m
Start-Up & Commissioning	£3.8m
Total Project Development	**£12.3m**
Total Capital Cost	
Total Capital Cost	£88.0m
Contingency	10%
Grand Total CAPEX	**£96.8m**

Table 30. EfW Benchmark - Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.5m
Maintenance	£2.4m
Total fixed OPEX	**£4.7m**
Variable Costs	
Electricity	£3.8m
Steam supply	£11.6m
Solvent	£0.4m
Other chemicals and consumables	£0.6m
Wastes	£1.1m
Plant auxiliary	£0.2m
Total variable OPEX	**£17.7m**
Total Operating Cost	
Total Operating Cost	£22.4m
Contingency	10%
Grand Total OPEX	**£24.7m**

9.3 Key Outputs

Table 31 contains a summary of values relating to the LCOC.

Table 31. EfW Benchmark - Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.3 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	7.8 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	2.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£96.8m	
Total annual OPEX	£24.7m	
Lifetime cost	£713.2m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£317.5m	Adjusted lifetime cost value based on discount rate.
LCOC	**£110/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart representing the LCOC and its constituent components is provided in Figure 24.

Figure 24. EfW Benchmark – LCOC

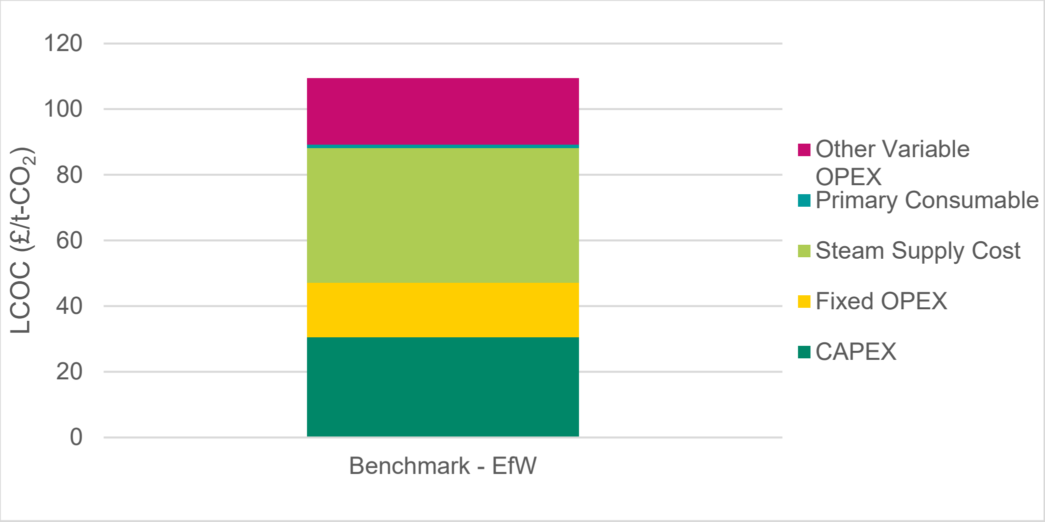


Figure 24 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95%.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Table 32 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 32. EfW Benchmark - Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	7.8 Mt	
LCOC	£110/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.6m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£197/t-MSW +£97/t-MSW +97% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£116/t-MSW +£15/t-MSW +15% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£213/t-MSW +£112/t-MSW +112% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

9.4 Modelling Assumptions

Table 33 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* report conducted as part of this assignment.

Table 33. EfW Benchmark - Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	High	Medium	Medium	EfW plants are designed for continuous high load operation as there is value in continuous, reliable treatment of waste. The presence of contaminants in the flue gas creates a risk in relation to operation with high availability. However, with sufficient flue gas pre-treatment, and effective solvent management, long term operation with high availability should be possible.
Input gas composition	See Appendix B	High	Low	Low	Changing waste composition has the potential to change the composition of the flue gas feed to the capture plant. However, changes to contaminants would largely be controlled by the flue gas pre-treatment systems.
Overall capital cost	See Table 29	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to capital cost. In addition, there is uncertainty relating to plant integration costs. However, overall cost uncertainty is low in comparison to other scenarios in this analysis.
Maintenance	See Table 30	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost. However, cost uncertainty is low in comparison to other scenarios in this analysis.
Electricity consumption	See Table 30	High	Low	Low	Electrical energy requirements are relatively well known for MEA capture plants with a defined configuration.
Steam consumption	See Table 30	High	Medium	Medium	Thermal energy requirements are relatively well known for MEA capture plants. However, thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 9.1.2	Medium	Medium	High	The arrangements for the provision of thermal energy will be site specific and may be more complicated or expensive for some plants. Thermal energy is the single largest operating cost for the plant. Conversely, some plants may be able to access steam with a lower unit cost than has been assumed.
Primary consumables (solvent)	See Table 30	Medium	Medium	High	Solvent may degrade faster than expected due to contaminants, leading to greater solvent consumption. This uncertainty can be reduced through solvent testing.
Input gas pre-treatment	See Table 28	Medium	Medium	High	EfW flue gas contains a wide range of contaminants and there is uncertainty relating to the pre-treatment measures required to control solvent degradation.
CO_2 conditioning	See Table 28	High	Medium	Medium	The amine capture process will absorb some of the residual contaminants in the flue gas input stream.

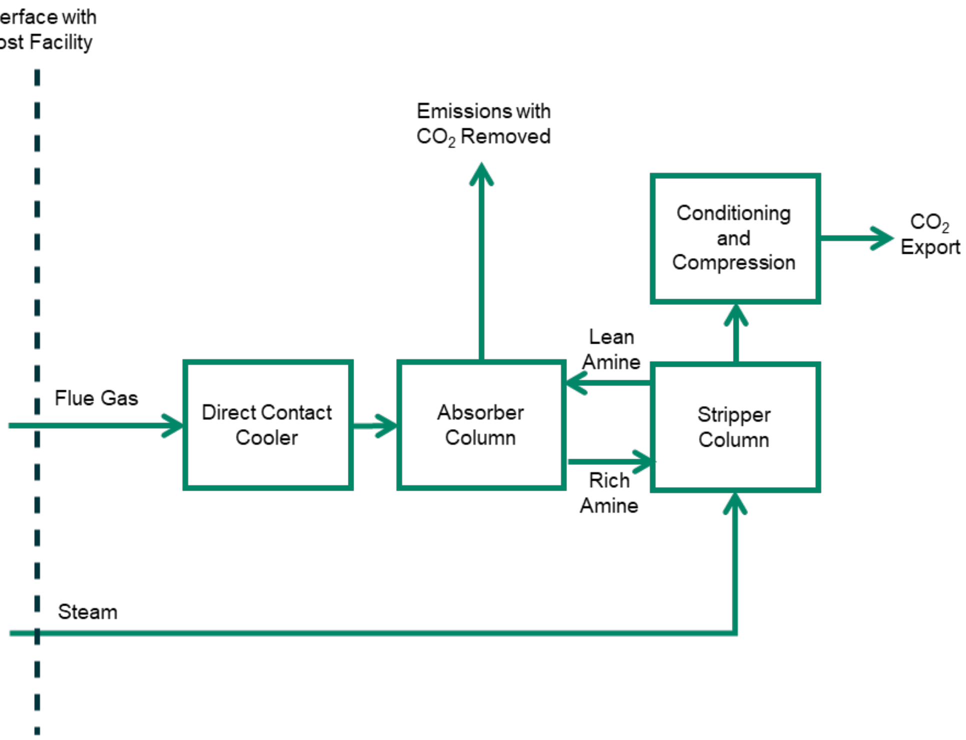
Overall, there is a *medium* level of uncertainty associated with the modelling of this scenario. Integration challenges will be highly site specific when capture technology is retrofitted to an EfW plant. Extensive modifications to steam systems and or emissions treatment equipment prior to the capture plant could increase costs.

10. Advanced Amine – EfW

10.1 Description of Scenario

This scenario involves retrofitting an existing EfW plant with advanced amine capture. The scenario is intended to represent how future generations of amine solvent capture plants may develop. The basic concept remains the same as the benchmark, but there are developments in solvent chemistry and across the process equipment. Figure 25 shows a block flow diagram of the process.

Figure 25. Block Diagram – Advanced amine capture



Several companies are developing advanced amine systems, including Mitsubishi Heavy Industries, Shell, Fluor, Carbon Clean and Aker. Details of the processes are provided in the *Review of Next Generation Technologies* report conducted as part of this study.

The dashed line in Figure 25 represents the interface with the host facility, as described in the EfW benchmark. The electricity input to the capture plant is not shown explicitly in the diagram but is assumed to be provided by the EfW plant.

A summary of technical information for the base process and carbon capture plant is presented in Table 34. A diagram of the capture process containing further information is provided in Appendix A.

Table 34. Advanced Amine – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 14 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Advanced amine capture**
Additional flue gas pre-treatment for capture plant	Potential limited modifications to existing acid-gas abatement system to reduce SO_X has not been included in the model, but may be required for some advanced amine systems depending on the solvent and input gas composition Flue gas blower to increase pressure Direct contact cooler to reduce temperature, with additional caustic treatment for SO_X reduction SCR for NO_X control has not been included in the model but may be required for some advanced amine systems depending on the solvent and input gas composition.
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Basic thermal integration of stripper and absorber columns Steam powered reboiler on stripper column Single stage thermal reclaiming with upstream solvent filter Improved thermal integration of process units relative to benchmark. Basic mechanical vapour recompression included on stripper column.
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	Improved amine solvent
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	42 tph (1000 tpd)
Steam supply	30 MW from EfW plant steam turbine This steam use represents the overall heat load of the capture plant
Electricity supply	6 MW from EfW plant

10.1.1 Flue Gas Pre-Treatment

Flue gases from waste combustion will contain a range of contaminants including a variety of acid gases and metallic compounds. Unless long term testing has been conducted, there is uncertainty as to how a particular solvent will perform when exposed to these contaminants. The far broader range of potential contaminants than for the gas fired power application increases the chances and variety of degradation reactions. Most outside of NO_X and SO_X have not been significantly studied to date. Long term solvent performance could impact project economics, particularly if solvent costs are high or if the equipment installed, or contractual conditions, limits the use of alternative solvents. When developing a solvent based capture plant that processes flue gases from waste combustion it is important to understand the likely behaviour of target solvents when exposed to representative flue gas.

Research and development work has been, and will continue to be, conducted into the development of new amine solvents that are more tolerant to impurities in flue gas. This work involves both formulating new solvents and the development of additives that can be used to enhance the performance of existing solvents. Over time it is anticipated that more information will become available in relation to the performance of different advanced amine solvents when exposed to flue gases from waste combustion.

Having a solvent that is more resistant to chemical degradation is valuable in the capture process as it could allow less pre-treatment of the incoming flue gas or require less solvent regeneration and replacement if the same amount of flue gas pre-treatment is applied. If solvent degradation is reduced, this would also be expected to reduce the mass of any harmful degradation products generated.

Despite this, there is evidence that advanced amine solvents may require somewhat stricter limits on input levels of NO_X and SO_X. This is likely due to most advanced amine systems deriving from non-primary amines and having higher specific replacement costs.

The level of additional treatment of the flue gas required will be site specific and depend on factors including the solvent selected, composition of incoming waste and the emissions abatement system already in place. In this scenario, it has been assumed that the flue gas pre-treatment equipment for the advanced amine system is the same as in the benchmark scenario as the known input requirements, though stricter, are still met by the same flue gas pre-treatment equipment.

10.1.2 Improved Solvent Performance

A number of improvement areas for advanced amine solvents have been identified, leading to improved process performance. These improvements include reduced volatility reducing evaporative losses of solvent, increased thermal stability reducing thermal degradation of solvent, reduced oxidation rate reducing oxidative degradation of solvent, and reduced thermal regeneration energy reducing energy consumption of the absorption and desorption process cycle. These factors result in significant savings on both solvent consumption and energy consumption.

These advancements in solvent performance come at the cost of an increased solvent price, as required for a tailored, more complex, and most often proprietary chemical when compared to the standard generic amine of the benchmark.

After accounting for both a reduction in solvent use and increase in solvent price, an overall reduction in solvent cost is expected for the advanced amine process. A significant reduction in solvent use has been assumed and reduced solvent regeneration requirements contribute to lower energy consumption. The generation of solvent waste products is likewise anticipated to reduce.

10.1.3 Energy Consumption

As with EfW benchmark, the thermal energy required is extracted from the main plant in the form of steam. Due to the volume of steam being extracted, it may be necessary to perform extensive modifications to the steam system of the host facility. Energy saving advances in the amine capture system that would mean less onerous modification of the base plant could be of value.

Different strategies can be used to improve the energy performance of amine capture plants. An overview of options is provided below.

Solvent improvements – Changes to the solvent chemistry can allow reductions in energy use at the capture plant. Areas of development include decreasing the heat of reaction or increasing the CO_2 absorption capacity of the solvent. Other factors, such as solvent viscosity and associated pumping costs, will also impact energy use at the plant.

The impact of changes to solvent chemistry on energy performance should not be considered in isolation. If a new solvent formulation allows reduced energy use, but costs more to purchase, is more susceptible to degradation, or produces more harmful degradation products, then overall it may be a less desirable solvent for the application being considered.

Thermal integration – Energy savings can be achieved through improvements to the design of thermal integration systems at the capture plant. This could include larger heat exchangers to allow lower approach temperatures in certain applications or heat recovery from equipment not directly related to the capture process, such as CO_2 compression. Mechanical vapour recompression systems can also be used to reduce steam demand, although the additional electrical consumption of this equipment must be considered.

While performance improvements are achieved using thermal integration there may be trade-offs between reduced energy consumption and equipment cost, reliability, ease of operation and operational flexibility. Competing priorities require to be balanced in the design of thermal integration systems.

Changes to process conditions - Changes to operating conditions such as temperatures or pressures in the capture plant can provide reductions in energy use. For example, increasing temperature and pressure in the stripping column will reduce subsequent CO_2 compression costs. As with other energy saving measures changes to process conditions may compromise other aspects of plant performance. Increased temperatures in the stripper column will increase thermal degradation of the solvent.

Each supplier of advanced amine solvent technology will use a combination of the above energy saving techniques. As knowledge and experience is gained in applying the equipment to different applications incremental improvements in the overall performance of amine capture plants are anticipated.

Advanced amine systems are expected to achieve valuable energy savings relative to the amine benchmark. A 35% w/w reduction in steam consumption and a 26% reduction in electricity use has been assumed relative to the benchmark MEA scenario. These figures are based on interpretation of vendor information on what the technology is likely to achieve in the future. The anticipated performance of advanced amine systems varies between technologies and literature sources, with some being less optimistic than assumed in this scenario.

10.1.4 Current Demonstration Status

Examples of amine capture at EfW facilities are described in the EfW benchmark section of this report. However, there are currently no operational amine capture plants at EfW facilities on the scale being modelled in this scenario. The plants that have been constructed use a variety of amine solvents, some of which are previous iterations of advanced amine solvents being marketed by leading suppliers. Details of solvent performance can be challenging to obtain as this information will have commercial value to the organisations who developed and operated the projects.

10.1.5 Technology Development

Key areas for technology development for advanced amine systems applied to EfW flue gases include:

- Construction of full-scale plants that achieve a high capture level for the host facility
- Demonstration of reliable operation
- Development and management of solvents that are suited to EfW flue gases. Understanding long term solvent performance will inform requirements in relation to solvent reclaiming and flue gas pre-treatment prior to the capture plant.
- Understanding and management of harmful solvent degradation products
- Reduction in energy use – thermal and electrical
- Development of practical solutions for integration with existing plants. This could include options to vary energy supply requirements between thermal and electrical sources to reduce the level of modifications required to the host plant. In addition, modifications to existing emissions abatement equipment could be optimised.
- Improvements in operational flexibility, particularly to meet variations in EfW fuel and flue gas
- Reduced equipment costs
- Modularisation and standardisation of designs

Collectively, developments in the above areas will aid the application of amine capture technology to EfW plants.

Hazards

The hazards present in an advanced amine capture plant will be similar to those in the benchmark amine case.

Advanced amine plants may use solvents based on secondary or tertiary amines. These amines have more potential to form nitrosamines degradation products. These compounds are of concern as they can be toxic, mutagenic, and carcinogenic. It is important to understand the formation, nature and management of degradation products generated by amine solvents. Solvent testing is an important part of this process.

As amine capture plants are deployed an associated regulatory framework will develop. Work to develop an evidence base for the definition of Best Available Techniques (BAT) for amine solvent post-combustion capture plants for EfW plants is currently in progress [15].

Maintenance

The overall process concept in an advanced amine plant is the same as in the benchmark case, so maintenance requirements will be similar. However, improvements in relation to plant maintenance are possible in several areas.

- **Operator feedback** – over time, feedback from owners and operators of amine capture equipment should help improve the design of equipment to allow maintenance costs to be reduced. For solvent-based capture technology, this process has already progressed further than for other next generation technologies.
- **Maintenance management systems –** there continues to be advances in maintenance management systems. Simulation software can allow the impact of different operating strategies and or conditions to be more accurately assessed.
- **Material selection and development** – materials science and construction techniques continue to evolve leading to potential reductions in maintenance requirements.
- **Skills development –** some items of equipment in the capture plants require specialist skills during maintenance. Establishment of a carbon capture industry in the UK will increase the number of individuals with the required skills.

10.2 Cost Summary

Table 35 and Table 36 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 35. Advanced Amine – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£2.8m
Capture Technology	£18.7m
Conditioning	£0.9m
Compression	£2.9m
Auxiliary Systems	£35.0m
Civil works	£14.4m
Total EPC	**£74.7m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.7m
Consultancy	£0.7m
Planning & Other Regulatory	£1.5m
Developer’s Costs	£5.2m
Start-Up & Commissioning	£3.7m
Total Project Development	**£12.1m**
Total Capital Cost	
Total Capital Cost	£86.8m
Contingency	10%
Grand Total CAPEX	**£95.5m**

Lessons learned, standardisation of designs and modularisation may help to reduce costs for advanced amine systems. However, these reductions may be balanced by the increased costs of thermal integration systems and equipment, and redundancy and design modifications required to allow consistent high availability operation. Overall capital costs are anticipated to be similar to current generation amine systems.

Table 36. Advanced Amine – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.4m
Maintenance	£2.4m
Total fixed OPEX	**£4.7m**
Variable Costs	
Electricity	£2.8m
Steam supply	£7.5m
Solvent	£0.1m
Other chemicals and consumables	£0.7m
Wastes	£0.3m
Plant auxiliary	£0.2m
Total variable OPEX	**£11.5m**
Total Operating Cost	
Total Operating Cost	£16.2m
Contingency	10%
Grand Total OPEX	**£17.9m**

Advances in solvent performance and energy efficiency are likely to lead to reduced operating expenditure on solvent, electricity, and steam over less advanced amine systems.

10.3 Key Outputs

Table 37 contains a summary of values relating to the LCOC.

Table 37. Advanced Amine – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.3 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	7.8 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	2.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£95.5m	
Total annual OPEX	£17.9m	
Lifetime cost	£541.8m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£253.2m	Adjusted lifetime cost value based on discount rate.
LCOC	**£87/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 26.

Figure 26. Advanced Amine – EfW LCOC

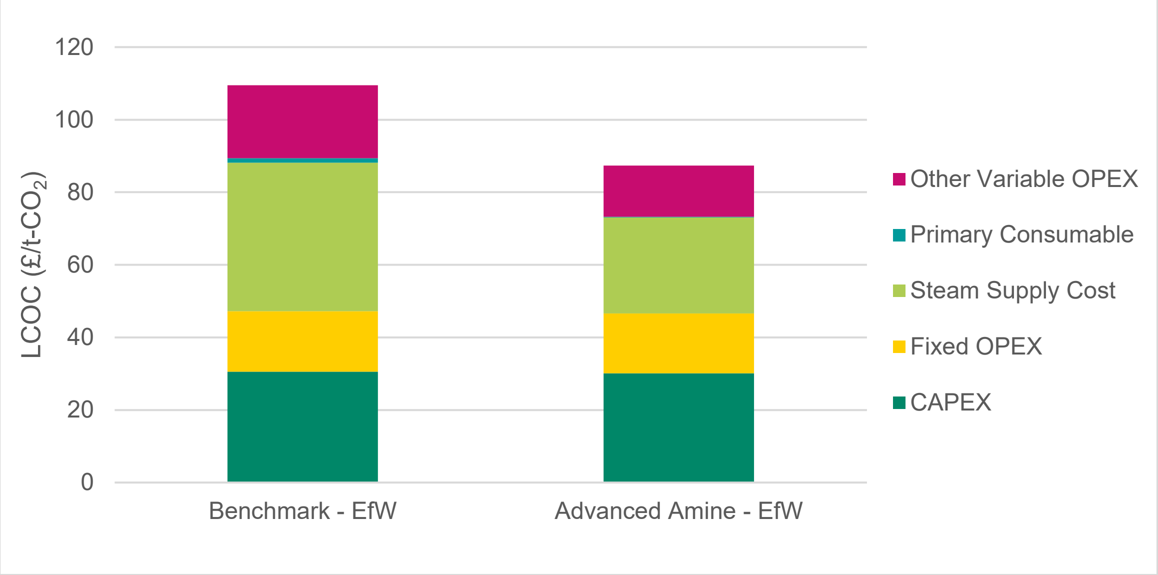


Figure 26 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the Benchmark and 95% for the Advanced Amine.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The advanced amine scenario shows a reduced LCOC relative to the benchmark case. The cost reduction is primarily due to reduced energy consumption.

Table 38 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 38. Advanced Amine – EfW Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	7.8 Mt	
LCOC	£87/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.6m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£178/t-MSW +£77/t-MSW +77% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£116/t-MSW +£15/t-MSW +15% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£193/t-MSW +£93/t-MSW +92% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

10.4 Modelling Assumptions

Table 39 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 39. Advanced Amine – EfW Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	High	Medium	Medium	Increased operational experience should reduce the availability risk associated with advanced amine capture technology. Furthermore, advanced amine systems are being developed by large companies, with the ability to offer meaningful guarantees in relation to plant performance. The level of availability risk will be technology and project specific and will continue to merit scrutiny during project development and funding.
Input gas composition	See Appendix B	High	Low	Low	Changing waste composition has the potential to change the composition of the flue gas feed to the capture plant. However, changes to contaminants would largely be controlled by the flue gas pre-treatment systems (see Input gas pre-treatment parameter below).
Overall capital cost	See Table 35	Medium	Low	Low	Technologies developed based on incremental improvements have a lower level of cost uncertainty than those using new concepts. Integration costs with the base process plant remain uncertain and highly site specific. See also Input gas pre-treatment parameter below.
Maintenance	See Table 36	Medium	Low	Low	Technologies developed based on incremental improvements have a lower level of cost uncertainty than those using new concepts.
Electricity consumption	See Table 36	High	Low	Low	Electrical energy requirements are relatively well known for advanced amine capture plants.
Steam consumption	See Table 36	Medium	Medium	High	Thermal energy requirements are relatively well known for advanced amine capture plants. However, thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 9.1.2	Medium	Medium	High	The arrangements for the provision of thermal energy will be site specific and may be more complicated or expensive for some plants. Thermal energy is the single largest operating cost for the plant. Availability of steam from, and the impact of extraction on, the host plant is highly site-specific and may impact the viability of retrofitting of carbon capture.
Primary consumables (solvent)	See Table 36	Medium	Medium	High	Solvent may degrade faster than expected due to contaminants, leading to greater solvent consumption. This uncertainty can be reduced through solvent testing. Significant reduction in solvent expenditure has been assumed relative to the benchmark.
Input gas pre-treatment	See Table 34	Medium	Medium	High	EfW flue gas contains a wide range of contaminants and there is uncertainty relating to the pre-treatment measures required to control solvent degradation.
CO_2 conditioning	See Table 34	High	Medium	Medium	The amine capture process will absorb some of the residual contaminants in the flue gas input stream.

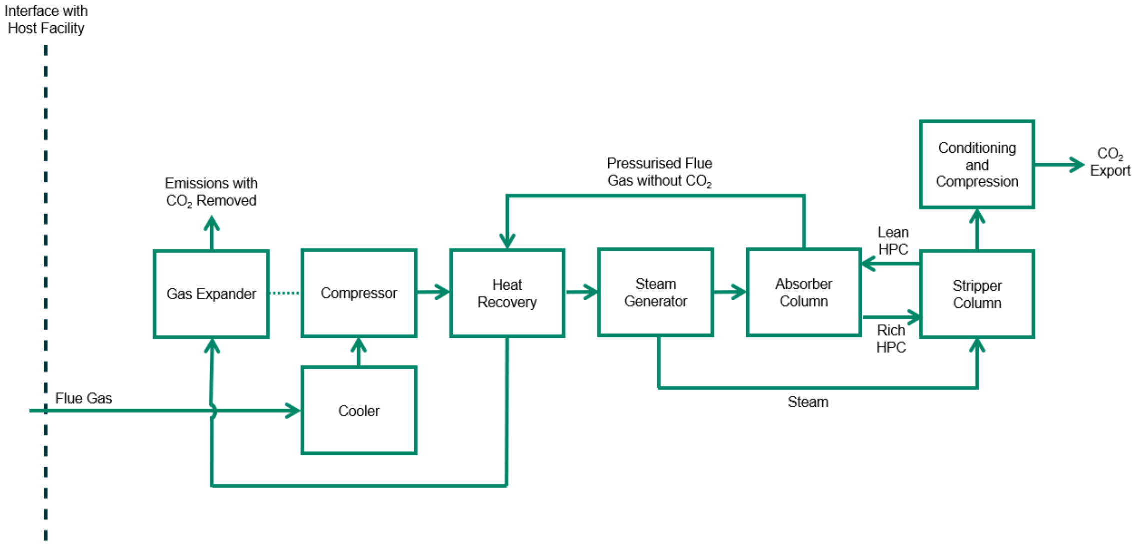
Overall, there is a *medium* level of uncertainty associated with the modelling of this scenario. Integration challenges will be highly site specific when a capture technology is retrofitted to an EfW plant. Further research into the generation and management of harmful solvent degradation products would be valuable.

11. Hot Potassium Carbonate – EfW

11.1 Description of Scenario

This scenario involves retrofit of an existing EfW plant fitted with a solvent-based capture process based on a hot potassium carbonate (HPC) solvent and CO2 Capsol's heat recovery process. Figure 27 shows a block flow diagram of the capture process, with the dashed line representing the interface between the existing EfW plant and the new capture plant.

Figure 27. Block Diagram – CO_2 Capsol on EfW



One important process difference in comparison to the benchmark case is that the system uses pressurised flue gas in the absorber column. The solvent is then regenerated by passing it to a stripper column where the pressure is reduced and the CO_2 is released. This alternative method of solvent regeneration means that electrical energy requirements are increased (to compress the incoming flue gas) and thermal energy requirements are decreased. CO2 Capsol offer a zero thermal energy input option where all thermal energy required for the stripper column is recovered from the process after the flue gas compression.

The CO2 Capsol process has following potential advantages:

- HPC is relatively low cost and less hazardous than other solvents, although it should be noted that some HPC processes use potentially harmful chemicals such as amines or piperazine to aid solvent performance. It is understood that the CO2 Capsol process does not.
- Energy for the system can be provided fully, or partly in the form of electricity. Steam for the stripper is generated within the capture plant so there is a reduced requirement for imported thermal energy. This may be an advantage in relation to overcoming integration challenges with the host facility. In the modelled scenario only a small amount of steam is imported from the host plant for use in CO_2 conditioning.

A summary of technical information for the base process and carbon capture plant is presented in Table 40. A diagram of the process containing further information is provided in Appendix A.

Table 40. Hot Potassium Carbonate – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 10 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion Capture using CO_2 Capsol process**
Additional flue gas pre-treatment for capture plant	Cooler to reduce temperature Flue gas compressor (to 7 bara)
Capture	Packed bed pressurised absorber column Gas expander to recover energy from absorber column discharge Packed bed stripper column Lean vapour flash compressor discharging to stripper column Flash steam compressor discharging to stripper column Steam powered reboiler on stripper column Solvent reclaiming – details unspecified
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	Hot potassium carbonate solution (HPC)
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	42 tph (1,000 tpd)
Steam supply	1 MW from main power plant for use in CO_2 conditioning. Steam for the stripper column is produced within capture plant using heat recovered from flue gas compressor.
Electricity supply	15 MW from EfW plant

11.1.1 Flue Gas Pre-Treatment

The incoming flue gas requires to be cooled and then compressed to around 7 bara prior to entry into the absorber column. This compression would require a large size, high power, compressor unit. CO2 Capsol's process diagram indicates that the compressor is directly coupled to both a motor and a gas expander that recovers energy from the pressurised exhaust of the absorber column.

This process stage would require a specialised compressor/expander item of equipment. The availability and costs of this piece of equipment at the required scale would need to be investigated during the development of a project. If a single compressor/expander unit was difficult to procure, other equipment configurations could be used for compressing the flue gas to the required pressure. However, this may have cost or energy consumption implications.

Similar to the amine solvent in the benchmark case the HPC solvent will form heat stable salts and degrade when exposed to contaminants such SO_X, NO_X and other contaminants that may be present in the EfW flue gas. No additional treatment has been assumed in this scenario to remove flue gas contaminants prior to entry into the capture plant. However, it should be noted that information was not available on degradation rates for HPC solvent when used on EfW flue gas. Solvent testing under representative conditions would reduce uncertainty in relation to solvent management costs and the optimum level of flue gas pre-treatment required.

11.1.2 Energy Consumption

There is no requirement for large amounts of steam to be extracted from the main power plant in this scenario. Only a small amount of imported steam is required for CO_2 conditioning. This is an advantage in that extensive steam system modifications at the existing EfW plant will not be required. It would also be an advantage in other sectors without easy access to steam.

The plant uses electrical energy to operate the flue gas compressor and mechanical vapour recompression systems. Thermal energy is then recovered and exchanged at various points inside the CO2 Capsol process. There is a moderate degree of complexity associated with the energy integration systems at the plant. For example, after cooling and compression, the flue gases pass through a further three heat exchangers prior to entry into the absorber column.

Efficiency or cost savings may be possible if a limited quantity of additional thermal energy was provided to the process by the EfW plant to reduce reliance on heat recovery systems included in the design. A decision on whether to provide additional steam could be made based on the volume of steam readily available from the existing system at the EfW plant. At many EfW sites the extraction of limited quantities of steam will be relatively simple, and low cost, because significant modifications to the steam system would not be required.

When comparing energy consumption figures across capture technologies it is important to remember that more than one unit of thermal energy can be extracted from a steam turbine for every unit of electrical energy sacrificed. The ratio of useful heat exported to the reduction in electrical energy output from a steam turbine is referred to at the Z ratio and will vary between different steam turbines. Direct comparison of steam and electrical power consumption figures is usually not appropriate.

11.1.3 Current Demonstration Status

HPC has been used commercially as a solvent in gas processing applications. However, it has not been used for post combustion CO_2 capture.

There have been three pilot projects using CO_2 Capsol process for post combustion capture, at scales of less than 2 tpd. Two of the projects were based at biomass-fired power plants and one at a coal-fired power plant. These projects may not have included all of CO_2 Capsol's proposed energy integration system due to their limited scale.

A study was carried out in 2020 assessing the feasibility and economics of using the CO_2 Capsol process on an EfW plant at a capture scale of 300 to 500 ktpa [16]. There are also proposals for deployment at Stockholm Exergi's biomass-fired CHP plant in Värtaverket, Sweden at a capture scale of up to 800 ktpa of CO_2 [17].

As far as we are aware there has not yet been any testing of the CO_2 Capsol process using flue gases from an EfW plant.

11.1.4 Technology Development

Measures that could be taken in relation to applying the CO2 Capsol technology to EfW flue gases include:

- Testing the solvent on representative input flue gas to validate performance, understand degradation characteristics and understand reclaiming requirements.

- Construction of an intermediate scale demonstration project to validate costs, reliability, and energy performance predictions. To prove that energy performance based on modelled scenarios can be achieved in a working plant, the configuration of any demonstration facility would need to match the modelled configuration and include all thermal integration design features. In addition, the scale would need to be sufficient so that mass and heat transfer characteristics of the demonstration plant were representative of a larger commercial facility.
- Development of configurations of the technology designed to supply thermal energy to third parties. The use of a pressurised system may provide opportunities for the efficient recovery of additional heat for export. For example, latent heat recovery from moist flue gases could take place at a higher temperature if the gases are pressurised. Recovered heat could then be supplied to an external heat customer such as a district heating network.

Due to the similarities between the processes, many of the areas for technology development in non-amine solvent capture systems are the same as those for amine systems on EfW plants, as described in Section 10.1.5.

As the energy for the CO2 Capsol technology can be provided entirely from electrical power, there are potential advantages in developing the process for industries where steam is not readily available. This could include applications in the cement industry. Application of the CO2 Capsol technology to the cement industry was not assessed in this report due to limitations in the number of scenarios that could be evaluated.

Hazards

The hazards present in a HPC solvent capture plant will be like those in the benchmark amine case. However, the process is different, with different operating pressures and temperatures. Like all process plants structured hazard identification and mitigation measures would be required throughout the design and development of the process.

Replacement of an amine-based solvent with HPC will reduce the hazard associated with the solvent. Potassium carbonate is used in the food industry and poses lower risk towards the environment and people. Understanding and management of the hazards associated with solvent degradation products, or contaminants collected by the solvent, will still be required at an EfW facility using HPC.

Maintenance

The overall process concept in a non-amine capture plant is like the benchmark amine cases, so maintenance requirements will be similar. If a solvent is less corrosive or has lower levels of degradation this may result in reduced maintenance requirements.

Processes that use more complex energy integration systems are likely to have increased maintenance requirements because of additional equipment. The CO2 Capsol process contains a large size compressor and expander, mechanical vapour recompression systems and a greater number of heat recovery heat exchangers than other solvent based capture processes.

The CO2 Capsol energy integration process is different from other solvent capture processes in several areas, and it has not been demonstrated at scale. Construction and operation of a demonstration facility would reduce uncertainty in relation to availability, capital and maintenance costs.

General improvements in relation to plant maintenance for solvent capture systems are possible in several areas, details are provided in Section 7.1.5.

11.2 Cost Summary

Table 41 and Table 42 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 41. Hot Potassium Carbonate – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£1.2m
Capture Technology	£13.7m
Conditioning	£0.9m
Compression	£3.1m
Auxiliary Systems	£33.8m
Civil Works	£14.4m
Total EPC	**£66.9m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.7m
Consultancy	£0.7m
Planning & Other Regulatory	£1.3m
Developer’s Costs	£4.7m
Start-Up & Commissioning	£3.3m
Total Project Development	**£10.8m**
Total Capital Cost	
Total Capital Cost	£77.7m
Contingency	10%
Grand Total CAPEX	**£85.5m**

Table 42. Hot Potassium Carbonate – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.3m
Maintenance	£2.1m
Total fixed OPEX	**£4.3m**
Variable Costs	
Electricity	£7.6m
Steam supply	£0.2m
Solvent	£0.1m
Other chemicals and consumables	£0.0m
Wastes	£0.2m
Plant auxiliary	£0.2m
Total variable OPEX	**£8.2m**
Total Operating Cost	
Total Operating Cost	£12.5m
Contingency	10%
Grand Total OPEX	**£13.8m**

11.3 Key Outputs

Table 43 contains a summary of the values relating to the LCOC.

Table 43. Hot Potassium Carbonate – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.3 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	7.8 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	2.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£85.5m	
Total annual OPEX	£13.8m	
Lifetime cost	£429.4m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£206.0m	Adjusted lifetime cost value based on discount rate.
LCOC	**£71/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 28.

Figure 28. Hot Potassium Carbonate – EfW LCOC

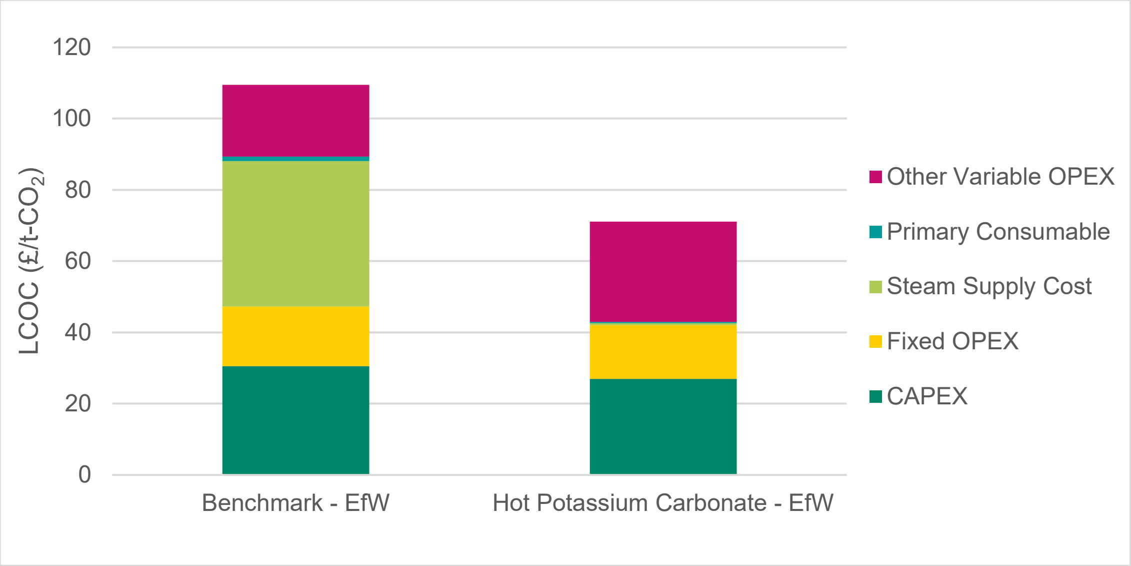


Figure 28 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for both scenarios.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The hot potassium carbonate scenario uses mainly electricity rather than steam as an energy input. This is most advantageous in situations where access to thermal energy is restricted or expensive. In the EfW application this is valuable as it could make integration with the host plant easier. Furthermore, this characteristic has the potential to be of value in other sectors, including cement, where there is not an existing steam cycle that can be used to supply thermal energy.

Table 44 contains a summary of the values relating to the impact of adding carbon capture on product cost.

Table 44. Hot Potassium Carbonate – EfW Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	7.8 Mt	
LCOC	£71/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.6m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£163/t-MSW +£63/t-MSW +63% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£116/t-MSW +£15/t-MSW +15% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£179/t-MSW +£78/t-MSW +78% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

11.4 Modelling Assumptions

Table 45 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 45. Hot Potassium Carbonate – EfW Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The capture concept has similarities to amine solvent capture, which is relatively well understood. However, there is currently no intermediate scale demonstration plant and there is complexity to the energy integrations systems included.
Input gas composition	See Appendix B	High	Low	Low	Changing waste composition has the potential to change the composition of the flue gas feed to the capture plant. However, changes to contaminants would largely be controlled by the flue gas pre-treatment systems.
Overall capital cost	See Table 41	Medium	Medium	High	The lack of an intermediate scale demonstration plant using a comparable energy integration system increases cost uncertainty. Reduced thermal energy demand should make integration with the host plant simpler.
Maintenance	See Table 42	Medium	Low	Low	It is anticipated that maintenance requirements will be similar to other solvent based systems. When a project is being developed it will be important to understand the maintenance requirements for the compressors across the plant.
Electricity consumption	See Table 42	Medium	Medium	High	Electrical energy is the single largest operating cost, so any changes may impact LCOC.
Steam consumption	See Table 42	High	Low	Low	Only small amounts of steam used for CO_2 conditioning.
Steam price	See Section 9.1.2	High	Low	Low	Only small amounts of steam used for CO_2 conditioning.
Primary consumables (solvent)	See Table 42	Medium	Medium	High	Solvent may degrade faster than expected due to contaminants, leading to greater solvent consumption. This uncertainty can be reduced through solvent testing.
Input gas pre-treatment	See Table 40	Medium	Medium	High	EfW flue gas contains a wide range of contaminants and there is uncertainty relating to the pre-treatment measures required to control solvent degradation.
CO_2 conditioning	See Table 40	High	Medium	Medium	The capture process will absorb some of the residual contaminants in the flue gas input stream.

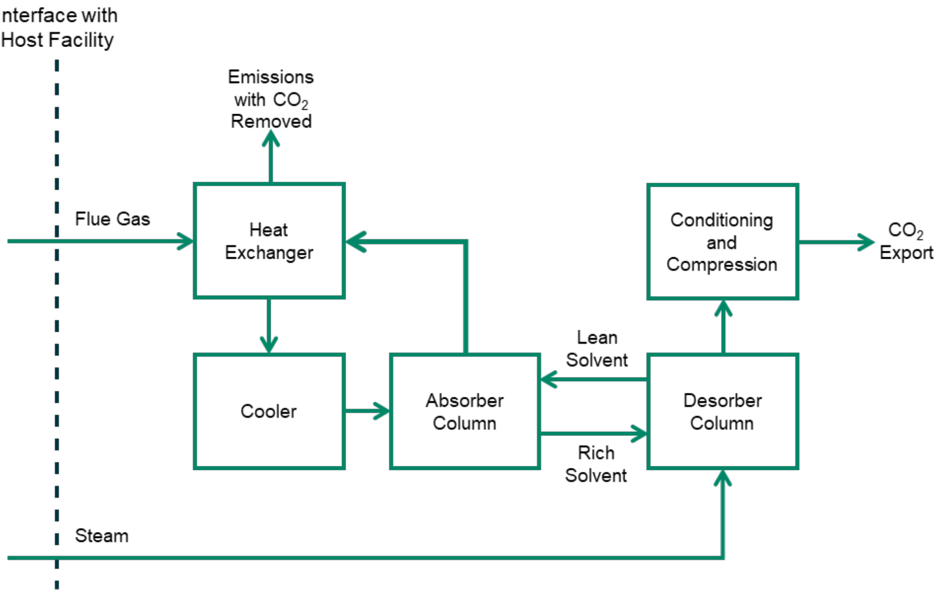
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. A less hazardous solvent is an advantage and the use of electrical energy rather than thermal could aid integration with the host plant. Solvent testing with representative flue gases and an intermediate scale plant could validate performance claims.

12. Non-Amine Solvent - EfW

12.1 Description of Scenario

This scenario involves retrofit of an existing EfW plant with a solvent capture process that uses a non-amine solvent. The basic concept is the same as the benchmark, but non-amine solvents have different properties and, as a result, changes to the process equipment are required. Figure 29 shows a block flow diagram of the capture process, with the dashed line representing the interface between the existing EfW plant and the new capture plant.

Figure 29. Block Diagram – Non-amine solvent



Although not shown explicitly in the diagram, it is assumed that any electricity required is provided by the host plant's steam turbine generator.

Several companies are developing solvent based capture systems using non-amine solvents. These include Baker Hughes, CO2 Capsol, C-Capture and SAIPEM. Claimed advantages of non-amine solvents typically include reduced energy use, reduced solvent costs, reduced solvent toxicity, and increased resilience to contaminants. Details of processes offered by these companies are provided in the *Review of Next Generation Technologies* report conducted as part of this study.

This technoeconomic scenario is based around information provided by C-Capture, considered as being representative of this class of technologies. However, as with all emerging technologies, there are limitations in the availability of cost and performance data for the modelled applications.

A summary of technical information for the base process and carbon capture plant is presented in Table 46. A diagram of the capture process containing further information is provided in Appendix A.

Table 46. Non-Amine Solvent – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 15 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion Non-amine solvent**
Additional flue gas pre-treatment for capture plant	Heat exchange with stream exiting absorber to reduce temperature Flue gas blower to increase pressure Cooler to reduce temperature
Capture (See Appendix A for diagram)	Packed bed absorber with water wash prior to discharge Thermal integration of stream exiting absorber column and incoming flue gas (as above) Desorber column Basic thermal integration of desorber and absorber columns Steam powered heat exchanger on desorber column Reclaiming – details unspecified
Compression	Single compression train Increased solvent resilience to thermal degradation allows desorber column to be operated a higher temperature and pressure (4 bara). This reduces CO_2 compression requirements.
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	C-Capture proprietary non-amine solvent
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	42 tph (1000 tpd)
Steam supply	21 MW from EfW plant This steam use represents the overall heat load of the capture plant
Electricity supply	6 MW from EfW plant

12.1.1 Flue Gas Pre-Treatment

One of the stated advantages of the C-Capture technology is that the solvent is more resistant to thermal and chemical degradation than amine solvents. Increased resilience to degradation would have multiple advantages, including in relation to allowing a lower level of flue gas pre-treatment to be provided.

C-Capture and other suppliers of non-amine solvents may have, or go on to, develop solvents with improved tolerance to contaminants found in flue gases. Historically, CO_2 has not been captured from combustion flue gases, so solvent tolerance to contaminants such as NO_2 and SO_2 has not been a priority. Amine solvents were originally selected for removal of CO_2 from natural gas, which does not contain NO_2 and SO_2.

C-Capture is understood to have conducted long duration tests with flue gases from biomass combustion (not waste) at Drax Power station, in Selby. Further funding has been allocated for development of the technology, which is a positive indication of performance. However, high quality test data relating to degradation of the C-Capture solvent is not publicly available and, as far as we have been able to ascertain, does not exist for operation on flue gas from waste combustion.

The importance of solvent testing is understood by C-Capture, and we understand that the organisation has plans for deployment of solvent compatibility units in 2022 and 2023 for long-term testing on real flue gases. This is a prudent next step for the development of this technology.

Flue gases from waste combustion contain a range of contaminants including a variety of acid gases and metallic compounds. Unless long term testing on representative flue gases under realistic conditions has been conducted, there is uncertainty as to how a particular solvent will perform when exposed to these contaminants. Long term solvent performance could impact project economics, particularly if solvent costs are high or if the equipment installed, or contractual conditions, limits the use of alternative solvents.

12.1.2 Thermal Energy

C-Capture claims that the energy required for their system is lower than that of MEA and of advanced amine blends. The justification provided is that the solvent has a lower heat of absorption and that the desorber column can be operated at higher temperature and pressure, reducing solvent evaporation and subsequent CO_2 compression requirements.

The extent to which this performance can be achieved will depend on the compatibility of the solvent with target flue gases, which should be determined through the planned testing program.

In addition to solvent performance testing, process plant of a representative scale is required to validate capital cost and thermal performance assumptions. Heat recovery systems and the thermal performance of a solvent test rig will not be representative of a much larger process plant. An intermediate scale demonstration plant would provide validation of predicted thermal performance, predicted plant costs, and allow demonstration of reliable operation.

As with the benchmark, the thermal energy required for this scenario is extracted from the main plant in the form of steam. Due to the volume of steam being extracted, it may be necessary to perform extensive modifications to the steam system of the host facility. The actual cost of thermal energy provision will vary between sites. When carbon capture projects are being investigated at specific EfW sites, the provision of thermal energy to the capture plant should be considered at an early stage of the design process.

12.1.3 Current Demonstration Status

C-Capture's solvent has been used to capture CO_2 at a 1 tpd pilot project at Drax power station, with campaigns running since 2019 [26]. The data gathered from this project is being used to conduct a design study of a full-scale plant on one of Drax's biomass-fired boilers, at a capacity of 10,000 tpd of CO_2.

A design project based on capturing 20 tpd of CO_2 at a demonstration plant using C-Capture's technology has recently received funding from BEIS. The second phase of this project intends to see the demonstration plant constructed and operated at Ince Bio Power Plant in Cheshire by 2025 [27].

The projects above are biomass applications and, as far as we have been able to ascertain, C-Capture's solvent has not yet been demonstrated on EfW plant flue gas.

12.1.4 Technology Development

Measures that could be taken in relation to applying C-Capture's technology to EfW flue gases include:

- Testing the solvent on representative input flue gas to validate performance, understand degradation characteristics and understand reclaiming requirements.
- Construction of an intermediate scale demonstration project to validate costs, reliability, and energy performance predictions.

Due to the similarities between the processes, many of the areas for technology development in non-amine solvent capture systems are the same as those for amine systems on EfW plants, as described in Section 10.1.5.

Hazards

The hazards present in a non-amine solvent capture plant will be similar to those in the benchmark amine case. However, the C-capture solvent, and many other non-amine solvents, are claimed to be less harmful and produce less harmful degradation products. A less hazardous solvent would clearly be an advantage in a solvent capture process with respect to plant operation and air emissions from treated flue gas.

It is difficult to say with certainty that any given solvent, or its degradation products, are not harmful without knowing the exact composition of the solvent and or degradation products. Manufacturers of proprietary solvents are, understandably, protective of technical details relating to their products. The competing needs of understanding hazards associated with new solvents, and protecting the intellectual property of solvent developers, is a key issue in developing the permitting regime associated with such plants.

Maintenance

The overall process concept in a non-amine capture plant is similar to the benchmark amine cases, and so maintenance requirements are anticipated to be similar. If a solvent is less corrosive, or has lower levels of degradation, this may result in reduced maintenance requirements. Processes that use more complex energy integration systems are likely to have increased maintenance requirements as a result of additional equipment.

General improvements in relation to plant maintenance for solvent capture systems are possible in several areas, details are provided in Section 7.1.5.

12.2 Cost Summary

Table 47 and Table 48 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 47. Non-Amine Solvent – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment (Included in Capture Technology cost)	£0.0m
Capture Technology	£23.6m
Conditioning	£0.9m
Compression	£2.3m
Auxiliary Systems*	£32.5m
Civil works	£14.4m
Total EPC	**£73.6m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.7m
Consultancy	£0.7m
Planning & Other Regulatory	£1.5m
Developer’s Costs	£5.2m
Start-Up & Commissioning	£3.7m
Total Project Development	**£11.9m**
Total Capital Cost	
Total Capital Cost	£85.5m
Contingency	10%
Grand Total CAPEX	**£94.0m**

*As stated in the Methodology, dry air-blast cooling has been assumed for all scenarios. At some sites other cooling options may offer cost reductions.

Table 48. Non-Amine Solvent – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.4m
Maintenance	£2.4m
Total fixed OPEX	**£4.6m**
Variable Costs	
Electricity	£3.2m
Steam supply	£5.4m
Solvent	£0.1m
Other chemicals and consumables	£0.0m
Demin water	£0.3m
Wastes	£0.2m
Plant auxiliary	£0.2m
Total variable OPEX	**£9.5m**
Total Operating Cost	
Total Operating Cost	£14.1m
Contingency	10%
Grand Total OPEX	**£15.5m**

12.3 Key Outputs

Table 49 contains a summary of values relating to the LCOC.

Table 49. Non-Amine Solvent – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.3 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	7.8 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	2.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£94.0m	
Total annual OPEX	£15.5m	
Lifetime cost	£482.3m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£230.2m	Adjusted lifetime cost value based on discount rate.
LCOC	**£79/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 30.

Figure 30. Non-Amine Solvent – EfW LCOC

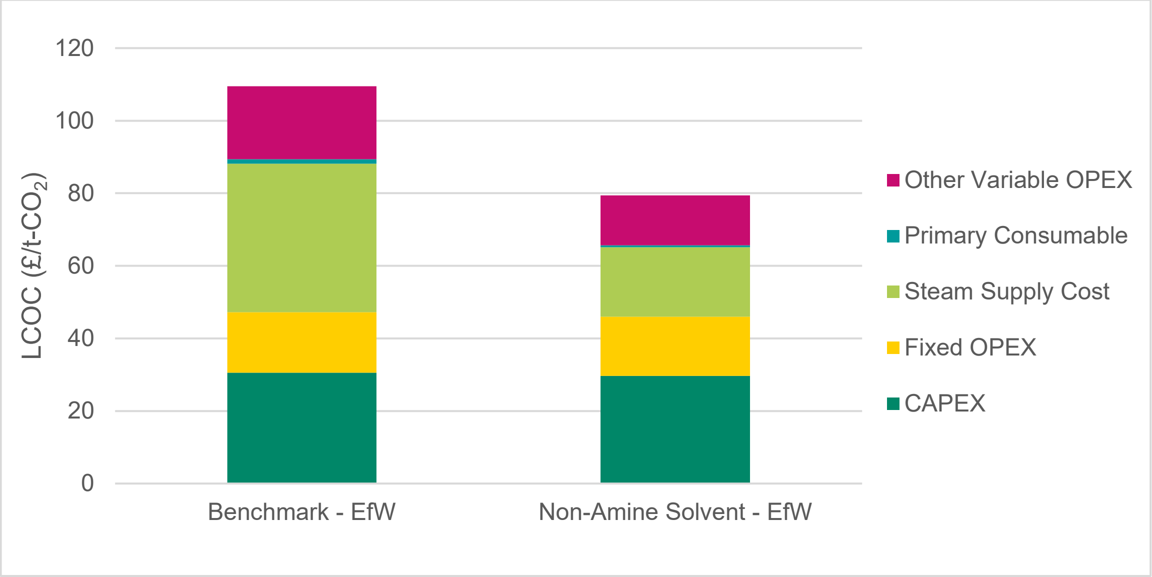


Figure 30 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for both scenarios.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The results show a reduction in LCOC relative to the benchmark. Performance ranges were provided by the technology supplier for some parameters used to derive the LCOC values. If more ambitious figures from the ranges were selected, then there would be a greater reduction in LCOC relative to the benchmark.

Table 50 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 50. Non-Amine Solvent – EfW Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	7.8 Mt	
LCOC	£79/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.6m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£171/t-MSW +£70/t-MSW +70% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£116/t-MSW +£15/t-MSW +15% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£186/t-MSW +£86/t-MSW +85% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

12.4 Modelling Assumptions

Table 51 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 51. Non-Amine Solvent – EfW Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The capture concept is similar to amine solvent capture, which is relatively well understood. However, the use of a solvent with different properties means that equipment will be different in some areas, and this creates availability risk. The C-Capture process has only been operated at a scale of 1 tpd.
Input gas composition	See Appendix B	High	Low	Low	Changing waste composition has the potential to change the composition of the flue gas feed to the capture plant. However, changes to contaminants would largely be controlled by the flue gas pre-treatment systems.
Overall capital cost	See Table 47	Medium	Medium	High	It is anticipated that capital requirements will be similar to established amine solvent-based systems. However, the lack of an intermediate scale demonstration plant increases uncertainty. Development experience could bring costs down to similar levels to other solvent systems. Integration costs with the base process plant remain uncertain and highly site specific.
Maintenance	See Table 48	Medium	Low	Low	It is anticipated that maintenance requirements will be similar to other solvent based systems. A less corrosive solvent has potential to reduce maintenance requirements.
Electricity consumption	See Table 48	Medium	Low	Low	Reductions in electrical energy requirements may be possible using non-amine solvents. However, performance claims remain to be validated at a scale sufficient to be representative of the modelled plant.
Steam consumption	See Table 48	Medium	Medium	High	Reductions in thermal energy requirements may be possible using non-amine solvents. However, performance claims remain to be validated at a scale sufficient to be representative of the modelled plant.
Steam price	See Section 9.1.2	Medium	Medium	High	The arrangements for the provision of thermal energy will be site specific and may be more complicated or expensive for some plants. Thermal energy is the single largest operating cost for the plant.
Primary consumables (solvent)	See Table 48	Medium	Medium	High	Advances in solvent chemistry and management that reduce usage are likely to be possible and may have already occurred. However, long duration demonstration with representative flue gases and reclaiming equipment is required to validate performance.
Input gas pre-treatment	See Table 46	Medium	Medium	High	Advances in solvent chemistry that increase resilience to chemical degradation are likely to be possible and may have already occurred. However, long duration demonstration with representative flue gases and reclaiming equipment is required to validate performance.
CO_2 conditioning	See Table 46	High	Medium	Medium	The solvent capture process may absorb some of the residual contaminants in the flue gas input stream.

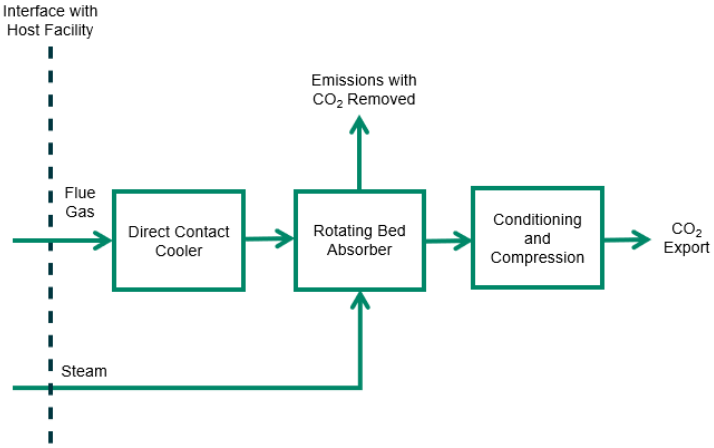
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. Non-amine solvents are a promising technology for waste combustion and a less hazardous solvent is an advantage. Testing on representative flue gases and an intermediate scale plant is required to validate performance claims.

13. Solid Sorbent – EfW

13.1 Description of Scenario

This scenario involves retrofit of an existing EfW plant with solid sorbent-based capture technology. Figure 31 shows a block flow diagram of the process, with the dashed line representing the interface between the existing EfW plant and the new capture plant.

Figure 31. Block Diagram – EfW with solid sorbent capture



Several companies including Svante, Kawasaki CO_2 Capture and TDA Research are active in developing sorbent-based technology for capturing CO_2 from industrial flue gases. Claimed advantages of sorbent-based capture systems typically include reduced energy use and eliminating the use of a hazardous solvent. Details of processes offered by these companies are provided in the *Review of Next Generation Technologies* report conducted as part of this study.

This technoeconomic scenario is based around information estimated by AECOM, considered as being representative of this class of technologies. As with all emerging technologies, there are limitations in the availability of cost and performance data for the modelled applications. Figure 31 shows a rotating bed absorber but other absorber configurations are available.

A summary of technical information for the base process and carbon capture plant is presented in Table 52.

Table 52. Solid Sorbent – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of MSW
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 5 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion Solid Sorbent**
Additional flue gas pre-treatment for capture plant	Potential limited modifications to existing flue gas treatment system Flue gas blower to increase pressure Direct contact cooler to reduce temperature
Capture	Rotary adsorption machine, with structured sorbent mounted on rotating fixed bed CO_2 separation from sorbent achieved by direct steam injection Doped silica sorbent on structured packing
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	42 tph (1,000 tpd)
Steam supply	45 MW from EfW plant steam turbine
Electricity supply	11 MW from EfW plant

13.1.1 Flue gas Pre-treatment

Sorbent based capture systems rely on sorbent materials with high surface area to allow CO_2 to be adsorbed onto the surface of the material. The adsorbed CO_2 is then released when a change in pressure and or temperature is applied to the sorbent. After the CO_2 has been released the cycle can be repeated.

Over time the sorbent material is degraded through a variety of mechanisms. Contaminants in the gas stream that are not released during the regeneration cycle will reduce the surface area of the sorbent over time and this will reduce adsorption capacity. The Svante rotating absorption machine does not involve the conveying of sorbent. However, for systems that involve sorbent conveying degradation can also occur due to physical damage caused by the conveying.

Some sorbent systems are understood to have good resilience to acid gases such as NO_2 and SO_2, with the gases being released from the sorbent with the CO_2 during regeneration. Where contaminants can pass through the capture system this may create a greater need to remove them by reaction with appropriate reagents in the downstream CO_2 conditioning part of the process.

The optimum level of flue gas pre-treatment prior to admission of input gases to a sorbent-based capture plant will depend on the vulnerability of the sorbent to degradation by flue gas contaminants and the cost of replacing the sorbent. Sorbent test data on representative flue gas will be required to make informed decisions relating to sorbent selection and the design and operation of flue gas pre-treatment equipment.

In this scenario no additional flue gas cleaning equipment has been assumed other than what is required for temperature and pressure adjustment of the incoming flue gas.

13.1.2 Energy Consumption

Thermal and electrical energy consumption figures are similar to the benchmark scenario. However, there are opportunities to improve energy requirements as sorbent materials develop. It is also important to note that energy performance is dependent on input gas conditions. It may be that sorbent systems will outperform solvents in specific applications, for example, where the concentration or partial pressure of CO_2 is higher.

As with the solvents in solvent-based systems a holistic view of sorbent performance is required. Improved sorbent performance in relation to energy use may be of no value if costs increase or the new sorbent has increased susceptibility to degradation.

As with the benchmark, the thermal energy required for this scenario is extracted from the main plant in the form of steam. Due to the volume of steam being extracted, it may be necessary to perform extensive modifications to the steam system of the host facility. The actual cost of thermal energy provision will vary between sites. When carbon capture projects are being investigated at specific EfW sites, the provision of thermal energy to the capture plant should be considered at an early stage of the design process.

13.1.3 Current Demonstration Status

Sorbent based separation technologies are used commercially in other gas processing applications. However, they are less developed than solvent based solutions for capturing CO_2 from flue gases.

Svante, Kawasaki CO_2 Capture and TDA Research are all active in developing sorbent-based technology for capturing CO_2 from industrial flue gases. Pilot plants of between 10 and 30 tpd of CO_2 capture have been constructed with plans for larger projects [28] [29] [30]. However, there is still a considerable gap in scale between these pilot plants and the 1000 tpd scale under consideration in this scenario. The scale-up challenges will vary depending on the architecture of the different systems used to contain the sorbent material.

The pilot plants that we are aware of processed flue gases from coal combustion and cement manufacture. These flue gases would be expected to have similar CO_2 concentrations to flue gas from EfW. However, flue gases from EfW may contain a wider range of contaminants and it will be important to understand any impact these contaminants may have on sorbent performance over its lifetime.

13.1.4 Technology Development

Areas for technology development in relation to sorbent-based capture technology are described below.

- Development of scaled-up unit sizes to allow large scale deployment without the need for high numbers of small units.
- Improvements to plant architecture to allow reliable and efficient operation while minimising construction costs. At present there are different competing plant architecture concepts for sorbent-based systems. These include systems that involve conveying the sorbent material, fixed beds and rotating fixed beds. As more systems are deployed the configuration of these arrangements may be optimised, and or it may be that one configuration demonstrates itself to be superior to the other arrangements.
- Demonstration of long-term reliable operation to reduce cost and performance uncertainty and build investor confidence.
- Development of sorbent materials with improved cost and performance characteristics. These could include CO_2 adsorption capacity, energy requirements for regeneration or resilience to physical or chemical degradation. Metal-organic frameworks (MOFs) are one area of active research and development in relation to carbon capture sorbents. For any new sorbent developed it is important to understand whether the claimed performance characteristics can be realised in a representative environment using available equipment.
- Increased understanding of the impact of flue gas contaminants on long term sorbent performance. This may allow improvements in sorbent performance and sorbent management to be made. This information will also inform choices relating to flue gas pre-treatment equipment. This will reduce uncertainties relating to maintenance costs and plant reliability. Developments in this area will require long term sorbent testing in a representative environment.
- Sorbent based capture systems, and particular classes of sorbent material, will be better suited to input gases from different industry sectors. As knowledge and experience develops different technologies can be

targeted towards the most appropriate capture application. One manufacturer of sorbent-based technology has indicated that carbon capture from steam methane reforming (with higher CO_2 concentration and lower levels of contamination) is a target application for their product.

Hazards

Sorbent systems can include large pressure vessels with cycling pressures. The application of existing regulations for pressurised equipment will provide a level of mitigation of the risks associated with this hazard. On systems where constant pressure is used temperature cycling will drive the absorption and desorption process. This creates hazards in relation to high temperatures and the potential for damage to equipment due to fatigue if it is inadequately designed for thermal cycling.

Some sorbents have the potential to be hazardous during certain handling operations. For example, exposure to airborne silica dust is hazardous as silica is a carcinogen. An assessment of the hazards associated with the sorbents being used, and the likelihood of exposure during maintenance activities and normal operations, should be made for any facility that uses sorbents.

As with the benchmark scenarios, there are hazards associated with the transportation and storage of CO_2.

There is no solvent used for capturing the CO_2 in this scenario, meaning any hazards associated with the release of solvent or solvent degradation products are eliminated.

Maintenance

If pre-treatment equipment is installed to control contaminant levels in the incoming flue gas, there will be additional maintenance requirements relating to this equipment.

The sorbent materials used will have a limited lifespan and periodic replacement will be required. However, the frequency of replacement and associated cost will vary depending on the sorbent used, the process architecture, operational load level and the composition of incoming gases. For any given system an assessment should be made based on operational data from a comparable application. The likely impact of any differences between the reference conditions and the proposed application would need to be considered.

Many sorbent-based systems will rely on a change in pressure to regenerate the sorbent material. Where pressure equipment is used, maintenance will be required in line with the relevant pressure equipment safety regulations.

If a rotating bed system is used to contain the sorbent material, then maintenance will be incurred relating to the mechanism that permits rotation and provides the relevant pressure sealing. The use of rotating equipment and pressure seals is widespread in process industries and there are established maintenance practices that can be employed. However, when an assessment of new plant is being made it will be important to identify any rotating components that are large, bespoke, or exposed to unusual conditions. Such components have the potential to impact overall maintenance costs for the plant, and in some cases, plant reliability.

There may also be additional maintenance associated with modifications made to allow the capture plant to interface with the existing EfW plant. This will be site specific but could include maintaining modifications to the steam system or emissions abatement equipment. If a capture plant is to be retrofitted to an existing EfW any changes to the maintenance requirements for the main process plant should be considered during the design process.

13.2 Cost Summary

Table 53 and Table 54 contain a summary of the capital and annual operational costs for the power plant and carbon capture plant.

Table 53. Solid Sorbent – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£2.8m
Capture Technology	£17.8m
Conditioning	£1.7m
Compression	£2.9m
Auxiliary Systems	£35.0m
Civil works	£14.4m
Total EPC	**£74.7m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.7m
Consultancy	£0.7m
Planning & Other Regulatory	£1.5m
Developer’s Costs	£5.2m
Start-Up & Commissioning	£3.7m
Total Project Development	**£12.1m**
Total Capital Cost	
Total Capital Cost	£86.8m
Contingency	10%
Grand Total CAPEX	**£95.4m**

Table 54. Solid Sorbent – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£1.4m
Maintenance	£2.4m
Total fixed OPEX	**£4.7m**
Variable Costs	
Electricity	£5.5m
Steam supply	£11.4m
Sorbent	£1.2m
Other chemicals and consumables	£0.1m
Wastes	£0.2m
Plant auxiliary	£0.2m
Total variable OPEX	**£18.5m**
Total Operating Cost	
Total Operating Cost	£23.2m
Contingency	10%
Grand Total OPEX	**£25.5m**

13.3 Key Outputs

Table 55 contains a summary of the values relating to the LCOC.

Table 55. Solid Sorbent – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.3 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	7.8 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	2.9 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£95.4m	
Total annual OPEX	£25.5m	
Lifetime cost	£733.9m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£324.3m	Adjusted lifetime cost value based on discount rate.
LCOC	**£112/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 32.

Figure 32. Solid Sorbent – EfW LCOC

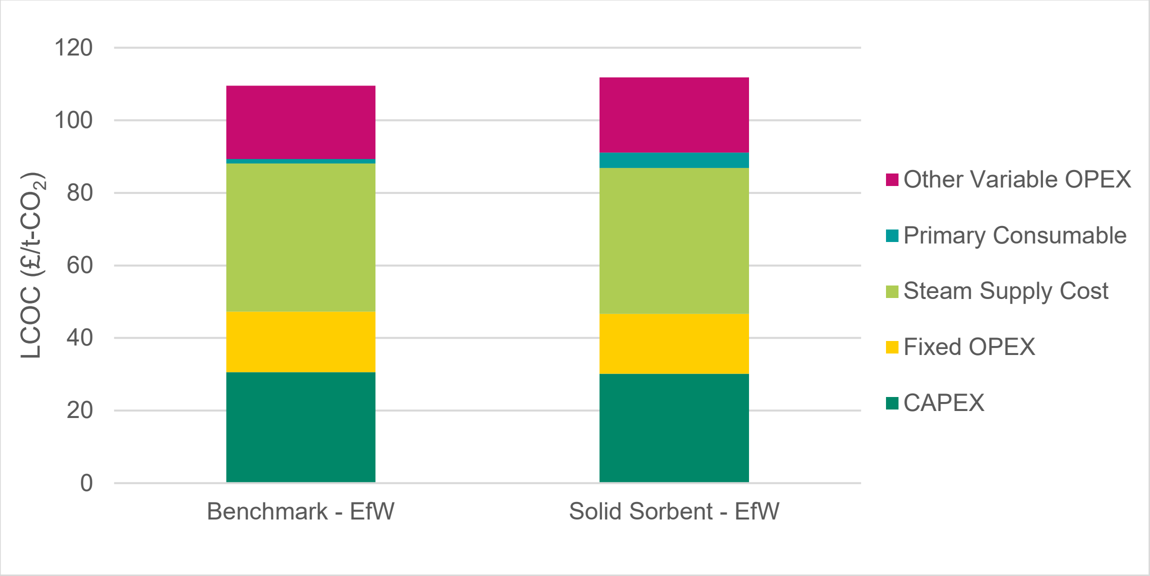


Figure 30 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for both scenarios.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The results show a similar LCOC to the benchmark. Performance ranges were reviewed for some aspects of performance used to derive the LCOC values. If more ambitious figures from the ranges were selected, then there would be a reduction in LCOC relative to the benchmark.

Table 56 contains a summary of the values relating to the impact of adding carbon capture on product cost.

Table 56. Solid Sorbent – EfW Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	7.8 Mt	
LCOC	£112/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.6m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£199/t-MSW +£99/t-MSW +99% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£116/t-MSW +£15/t-MSW +15% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£215/t-MSW +£114/t-MSW +114% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

13.4 Modelling Assumptions

Table 57 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 57. Solid Sorbent – EfW Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The limited scale of pilot plants and the lack of operation on EfW flue gas creates uncertainty in relation to operation with high availability at the modelled scale.
Input gas composition	See Appendix B	High	Low	Low	Changing waste composition has the potential to change the composition of the flue gas feed to the capture plant. However, changes to contaminants would largely be controlled by the flue gas pre-treatment systems.
Overall capital cost	See Table 53	Low	Medium	Very high	The limited scale of pilot plants and bespoke nature of the equipment creates uncertainty in relation to overall capital cost.
Maintenance	See Table 54	Medium	Medium	High	The limited scale of pilot plants and the lack of operation on EfW flue gas creates uncertainty in relation to maintenance cost.
Electricity consumption	See Table 54	Low	Low	Medium	Data on electrical consumption is limited. However, uncertainty relating to electrical energy requirements has a lower impact than uncertainty relating to steam consumption.
Steam consumption	See Table 54	Medium	Medium	High	Thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 9.1.2	Medium	Medium	High	The arrangements for the provision of thermal energy will be site specific and may be more complicated or expensive for some plants.
Primary consumables (sorbent)	See Table 54	Low	Medium	Very High	There has been limited long term testing of sorbents on representative EfW flue gas. This creates uncertainty in relation to sorbent lifetime and replacement and disposal costs.
Input gas pre-treatment	See Table 53	Medium	Medium	High	Some acid gas contaminants are understood to pass through the sorbent system with little interaction and this is an advantage in relation to flue gas pre-treatment. However, there has been limited long term testing of sorbents on representative EfW flue gas.
CO_2 conditioning	See Table 53	Medium	Medium	High	Some acid gas contaminants are understood to pass through the sorbent system with little interaction and end up in the CO_2 stream. This may increase requirements for CO_2 conditioning prior to export.

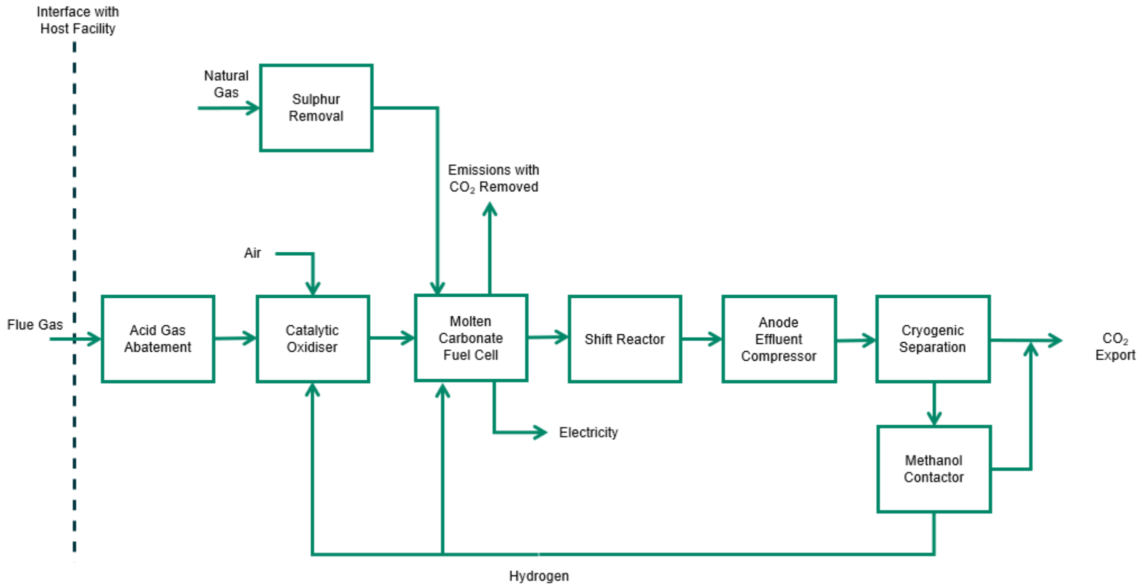
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. Pilot plants are of limited scale and there is a lack of operational experience on EfW flue gas. Testing on representative flue gases and an intermediate scale plant is required to validate performance claims.

14. Molten Carbonate Fuel Cell – EfW

14.1 Description of Scenario

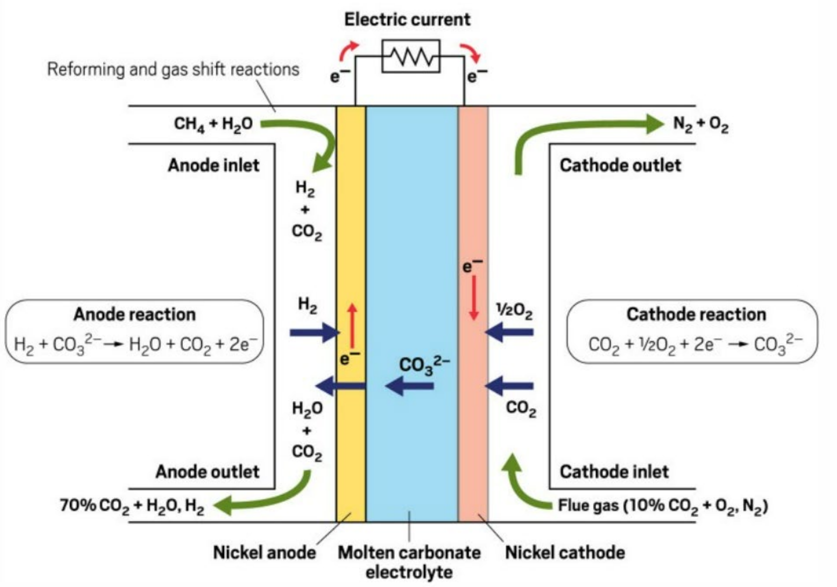
This scenario involves retrofit of an existing EfW plant with a molten carbonate fuel cell (MCFC) based post combustion capture process. Figure 33 shows a block flow diagram of the process, with the dashed line representing the interface between the existing EfW plant and fuel cell capture plant.

Figure 33. Block Diagram – MCFC capture process



A MCFC is an electrochemical device in which CO_2 is reduced to form carbonate ions (CO_3^{2-}) before being oxidised to CO_2. The energy to drive the process is derived from the oxidation of natural gas (CH_4), with electricity also being generated in the process. Figure 34 shows the chemical reactions and capture mechanism within the MCFC.

Figure 34. MCFC carbon capture mechanism [31]



A summary of technical information for the base process and carbon capture plant is presented in Table 58. A diagram of the capture process containing further information is provided in Appendix A.

Table 58. Molten Carbonate Fuel Cell – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW Plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 52 MW net electrical capacity with carbon capture. The additional electricity is generated by the MCFC.
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion MCFC**
Power output	26.3 MW net electrical output (from MCFC)
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure Limestone flue gas desulphurisation to further reduce SO_X Bag filters to further reduce particulates Catalytic oxidation to oxidise residual H_2 and CO and generate heat
Capture	Desulphurisation of natural gas fuel input Molten carbonate fuel cell for separation of CO_2 from flue gas Shift reactor to convert residual CO in anode outlet gas Condenser to remove H_2O from anode outlet gas Thermal integration system Steam turbine
Compression	Single compression train
Conditioning	Cryogenic CO_2 separation unit CO_2 separation from hydrogen recycle using methanol contacting
CO_2 capture level	96% of CO_2 emissions from flue gas during normal operation ~100% of CO_2 emissions from natural gas used
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	53 tph (1,275 tpd) as CO_2 Liquid phase The CO_2 is generated in the liquid phase because of the cryogenic conditioning equipment used. This would be an advantage for export to higher pressure pipelines as the pressure can be increased by pumping rather than compression. If gas phase CO_2 is required at the export pressure assumed in this scenario, then regasification equipment and additional thermal energy would be required. These additional costs would increase the LCOC.
Natural gas supply	5 tph
Steam supply	No steam required from EfW plant during normal operation
Electricity supply	No electricity required from EfW plant during normal operation

14.1.1 Flue Gas Pre-Treatment

The MCFC requires lower levels of contaminants in the incoming flue gas than other capture technologies. There will be challenges associated with reliably protecting the MCFC stack against damage from contaminants without incurring excessive equipment costs.

Additional particulate abatement equipment has been included in this scenario. When developing projects using MCFCs, the requirement for additional particulate abatement equipment should be confirmed on a case-by-case basis based on review of existing equipment and input specification for the selected MCFC.

In most EfW plants, additional acid gas removal equipment will be required to reduce SO_X levels to around 0.4 ppmv. A flue gas desulphurisation polishing unit will be required. Due to the low tolerance of the MCFC to SO_X, the natural gas entering the MCFC must be de-sulphurised to remove any traces of sulphur.

The additional particulate and SO_X abatement equipment will reduce the levels of other contaminants present in the EfW flue gas admitted to the MCFC. Like with other capture technologies uncertainty in relation to pre-treatment requirements and the lifespan of key components (the fuel cell) is reduced by testing with representative flue gas.

NO_X contamination in the flue gas is less of an issue for the MCFCs than some capture technologies. The MCFCs can remove 70% or more of the NO_X in the flue gas.

14.1.2 Energy Use

The energy input to the MCFC comes from natural gas. The MCFC capture process results in a net surplus of electricity generation and, with limited modifications, can also be used to generate hydrogen. In the modelled scenario the hydrogen produced is recycled and provides energy to the MCFC. If the CO_2 is captured and stored, the electricity and hydrogen generated will be low carbon.

In the process, steam (or water) is added upstream of the MCFC module to allow reforming of the natural gas to take place in the MCFC. In addition, a limited amount of steam is required for humidification of the natural gas entering the sulphur removal beds.

The MCFC generates excess steam beyond what is required by the facility. In the modelled scenario this steam is used to drive a steam turbine. The basis of the modelling conducted and performance of the MCFC came from a recent publication on the subject [32]. The excess steam available could alternatively be exported to provide a source of low carbon heat if there was a demand for thermal energy in the local area.

During normal operation the electrical and steam requirements of the system will be met using electricity and steam generated by the MCFC. Electrical connections to the host EfW plant would be required for start-up of the MCFC. Depending on the complexity of connecting to the host plant, steam required for start-up could be provided by either the EfW plant or a dedicated start-up boiler.

14.1.3 Current Demonstration Status

A 2.8 MWe MCFC power plant capturing CO_2 from the exhaust of a coal-fired power plant was supported by the US DOE in 2015. Subsequently in 2016, partnering with Exxon Mobil, another pilot at a coal and gas-fired power plant in Alabama, USA, was tested at 54 tpd CO_2 Capture.

In 2019 FuelCell Energy extended their relationship with Exxon Mobil with plans to install a demonstration unit at Exxon’s Rotterdam Refinery, data on the scale of the unit is not available. In the same year a FEED study was announced for an 85 tpd CO_2 Capture unit for Drax Power Station, UK.

FuelCell Energy have recently been awarded $6.8m by Canada’s Clean Resources Innovation Network which will be used to install their technology at the Scotford Upgrader site in Alberta, Canada [33].

There are currently no examples of MCFCs being used to capture carbon at the scale required for this scenario or being applied to an EfW plant.

14.1.4 Technology Development

The use of methane (natural gas or biomethane) and the potential to generate low carbon electricity and hydrogen mean that the economics of capture using MCFC is fundamentally different to other capture technologies. This difference may provide opportunities in relation to the application of MCFCs. For example, where gas is available, and a supply of low carbon electricity or hydrogen is required in a certain area.

Another important difference to other capture technologies is that MCFCs are modular. Even in the future if module sizes increase it is anticipated that large installations will comprise of a bank of MCFC modules. This could be an advantage in relation to allowing a smaller facility to be constructed with the option for subsequent expansion if desired.

Key for the development of MCFC technology for use as a capture technology at an EfW plant is the construction of a demonstration facility to provided baseline cost and performance information in this application.

Areas for technology development specific to MCFC technology include:

- Demonstration of reliable full system operation under representative conditions
- Optimising the structure of the MCFC stack
- Advancements in synthesising suitable electrode materials
- Advancements in catalysts used in the membrane electrode assembly
- Optimising flue gas pre-treatment systems to reliably protect the MCFC at an acceptable cost
- Identifying the most suitable industries to use MCFC based capture

Hazards

Key hazards in an MCFC facility are detailed below:

- High temperatures in and around the MCFC unit
- Pressurised equipment
- Electricity generated by the MCFC
- Alkali reagents used in the flue gas pre-treatment
- Fuel supply – natural gas
- Low temperatures associated with the cryogenic CO_2 conditioning equipment
- Methanol used in CO_2 separation
- Hydrogen gas
- The transportation and storage of CO_2

The first five of these hazards will already be present in some form at the host EfW facility.

Maintenance

Upstream of the MCFC modules treatment of the flue gas is required using alkali reagents and bag filters. Operators at the host EfW facility will be familiar with this kind of equipment. However, systematic, and effective operation and maintenance of the units will be required as any performance issues in this part of the process have the potential to damage the MCFC modules.

The MCFC modules at the core of the capture process have no moving parts, which is an advantage in relation to maintenance. However, MCFC modules will degrade and have a limited lifespan. Degradation rates will depend on the MCFC module used and the effectiveness of upstream contaminant removal.

Downstream of the MCFCs the cryogenic CO_2 upgrading system contains an array of pumps, compressors, and heat exchangers. While the maintenance requirements of this equipment are generally well understood, understanding the details of the equipment configuration with respect to redundancy and availability will be important in relation to understanding maintenance requirements.

The MCFC system also contains catalytic reactors, including the oxidiser prior to the MCFC, for oxidising CO and H_2, and the shift reactor after the MCFC for converting CO and H_2O to CO_2 and H_2. Periodic replacement of catalysts in these reactors will be required.

14.2 Cost Summary

Table 59 and Table 60 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 59. Molten Carbonate Fuel Cell – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£15.6m
Capture Technology	£14.2m
Conditioning	£3.9m
Compression	£6.9m
Auxiliary Systems	£38.0m
Civil works	£17.1m
Total EPC	**£95.8m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£1.0m
Consultancy	£1.0m
Planning & Other Regulatory	£1.9m
Developer’s Costs	£6.7m
Start-Up & Commissioning	£4.8m
Total Project Development	**£15.4m**
Total Capital Cost	
Total Capital Cost	£111.2m
Contingency	10%
Grand Total CAPEX	**£122.3m**

Table 60. Molten Carbonate Fuel Cell – EfW Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration	£1.8m
Maintenance	£3.1m
Total fixed OPEX	**£5.8m**
Variable Costs	
Natural gas	£14.8m
Electricity	-£13.3m
Steam supply	£0.0m
MCFC replacement	£1.4m
Other chemicals and consumables	£0.0m
Wastes	£0.1m
Plant auxiliary	£0.2m
Total variable OPEX	**£3.2m**
Total Operating Cost	
Total Operating Cost	£9.0m
Contingency	10%
Grand Total OPEX	**£9.9m**

14.3 Key Outputs

Table 61 contains a summary of values relating to the LCOC.

Table 61. Molten Carbonate Fuel Cell – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.4 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	10.0 Mt	Based on annual CO_2 capture and design life. The mass of CO_2 captured in the MCFC EfW scenario is higher than the other EfW scenarios as additional CO_2 from the use of natural gas is captured.
Discounted lifetime CO_2 captured	3.7 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£122.3m	
Total annual OPEX	£9.9m	Includes annualised cost of replacing MCFC units
Lifetime cost	£370.0m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£203.9m	Adjusted lifetime cost value based on discount rate.
LCOC	**£55/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. In the MCFC scenarios more CO_2 is captured due to the CO_2 from the natural gas used also being captured in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 35.

Figure 35. Molten Carbonate Fuel Cell – EfW LCOC

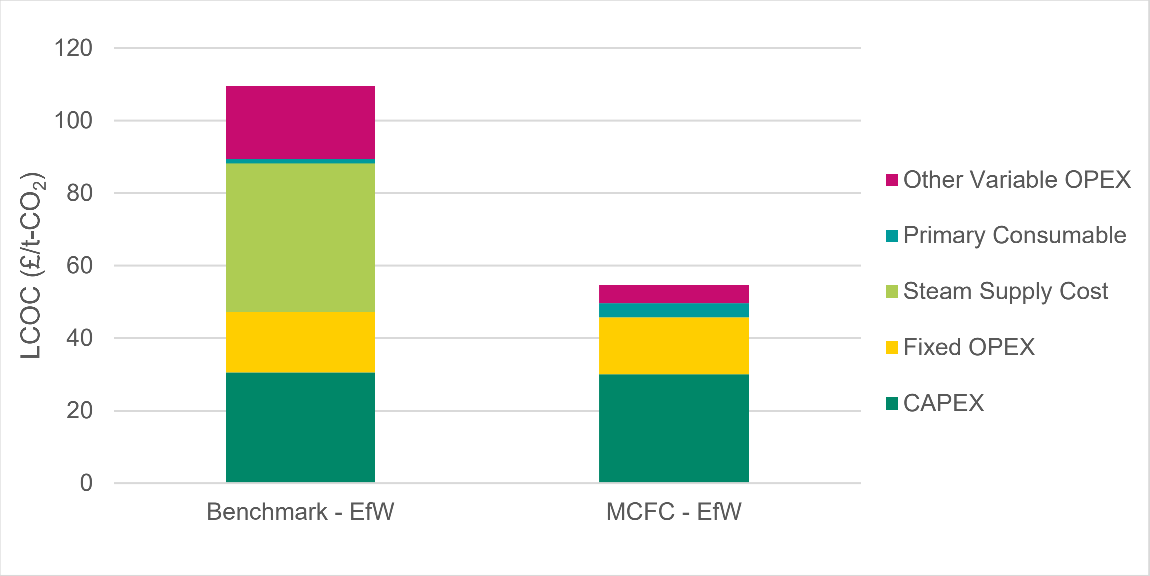


Figure 35 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is c.95% for both scenarios.
3. Both scenarios produce pipeline grade CO_2. In the MCFC scenario, it is produced in liquid phase.
4. The MCFC also consumes natural gas and generates electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The ‘Other variable OPEX’ segment in the MCFC scenario include both a natural gas cost and a negative operating cost resulting from electricity export.
5. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the EfW and cement sectors, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately.
6. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

A reduction in LCOC is indicated relative to the benchmark scenario. The MCFC requires more onerous control of flue gas contaminants than other technologies included in this report. Therefore, the results obtained are more reliant on the cost and performance of the flue gas pre-treatment equipment than in other scenarios. Validation of cost and performance data for suitable flue gas pre-treatment systems will be an important part of developing MCFCs for use in industrial capture applications.

Table 62 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 62. Molten Carbonate Fuel Cell – EfW, Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	10.0 Mt	
LCOC	£55/t	From calculations above
Lifetime CO_2 residual emissions	0.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£5.4m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£163/t-MSW +£62/t-MSW +62% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£115/t-MSW +£15/t-MSW +14% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£177/t-MSW +£77/t-MSW +77% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

14.4 Modelling Assumptions

Table 63 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 63. Molten Carbonate Fuel Cell – EfW Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The limited scale of pilot plants and the lack of operation on EfW flue gas creates uncertainty in relation to operation with high availability at the modelled scale.
Input flue gas composition	See Appendix B	High	Medium	Medium	The MCFC requires lower levels of contaminants than other capture technologies and performance on treated EfW flue gas remains to be demonstrated.
Overall capital cost	See Table 59	Medium	Medium	High	The limited number of examples of this technology creates unavoidable uncertainty in relation to capital cost. Risk magnitude could be controlled by adding modules to an initially smaller project.
Maintenance	See Table 60	Medium	Medium	High	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost.
Electricity generation	See Table 60	Medium	Medium	High	If the MCFC installation has a lower overall efficiency than predicted, then less power will be available to export. The generation of low carbon electricity could be an advantage at many sites, provided that there is a demand for the power, or it can be exported.
Steam consumption	See Table 60	High	Low	Low	Steam consumption is relatively low at a MCFC capture plant, and the MCFC process can generate excess steam through waste heat recovery. The scenario assumes no steam will come from the host EfW plant.
Steam price	See Section 9.1.2	Medium	Low	Low	Steam consumption is relatively low at a MCFC capture plant, and the MCFC process can generate excess steam through waste heat recovery. The scenario assumes no steam will come from the host EfW plant.
Natural gas consumption	See Table 60	High	Medium	Medium	If the MCFC installation has a lower degree of heat integration than predicted, then natural gas consumption would increase.
Primary consumables (MCFC module)	See Table 60	Low	Medium	Very High	When using natural gas and air (rather than flue gas) a lifespan in the order of seven years could be expected from a MCFC stack. However, the lifespan of the MCFC remains to be proven in representative conditions. Any performance issues in upstream flue gas equipment have the potential to reduce cell life.
Input gas pre-treatment	See Table 58	Medium	Medium	High	The lower contaminant levels required in the input gas for the MCFC can be achieved by installing additional flue gas pre-treatment equipment. There will be challenges associated with reliably protecting the MCFC stack against damage from contaminants without incurring excessive equipment costs.
CO_2 conditioning	See Table 58	Medium	Low	Low	The more extensive input gas pre-treatment required by the MCFC will be an advantage in relation to post capture CO_2 conditioning. Hydrogen and water are removed from the CO_2 using well-established process technologies. However, if gas phase CO_2 is required, rather than liquid phase, then additional equipment and thermal energy will be required.

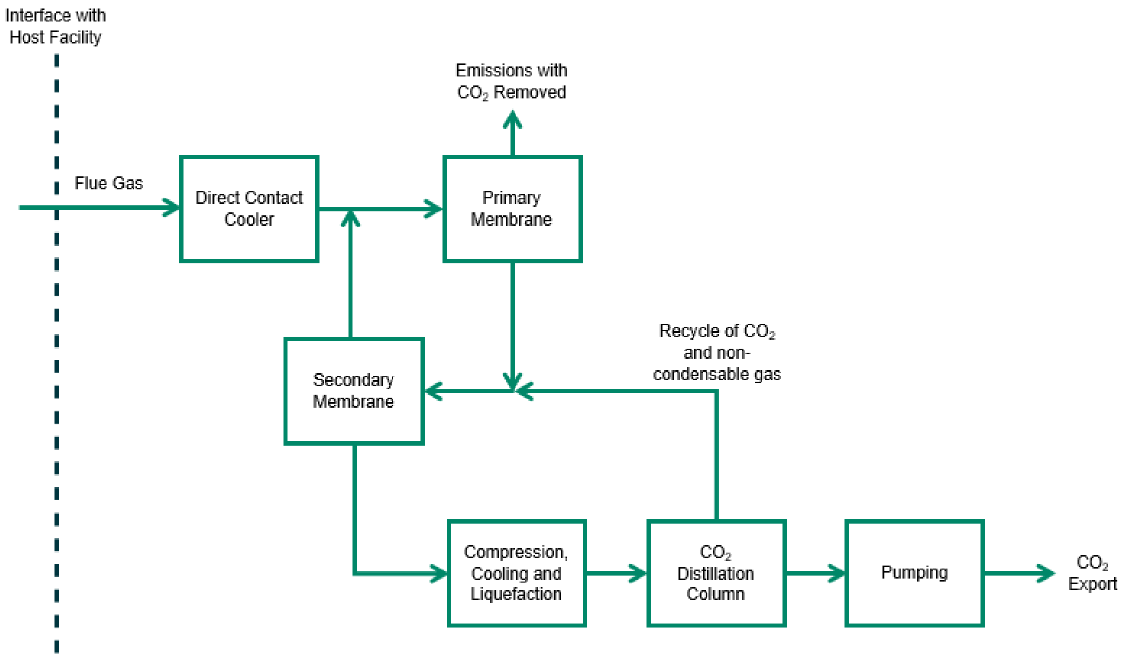
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. MCFCs have potential advantages in relation to integration with the host plant, modular construction and the production of low carbon electricity. Testing on representative flue gases is required to validate cost and performance assumptions.

15. Polymeric Membrane – EfW

15.1 Description of Scenario

This scenario involves retrofit of an existing EfW plant with a post combustion polymeric membrane capture plant. Figure 36 shows a block flow diagram of the process, with the dashed line representing the interface between the existing EfW plant and the new capture plant.

Figure 36. Block Diagram – Polymeric Membrane capture process



Membrane based capture systems have potential advantages over other capture technologies. Finding applications where these advantages are of most value will aid the development of membrane capture technology. Advantages of membrane systems are detailed below.

- Energy input from electricity, rather than steam, reduces integration challenges when retrofitting to an existing industrial facility. This will be an advantage in any industry sector where large volumes of steam are not readily available. Where electricity is available, there is no reliance on natural gas or other chemical fuel.
- The membrane separation process does not use chemicals to achieve the separation, so costs, hazards and permitting requirements relating to chemical handling, emissions and disposal are reduced.
- A modular design means that units can be pre-assembled under controlled conditions with installation scales delivered as required.
- The operating principal of the membranes gives good operational flexibility including fast response to load changes and high turndown.

A summary of technical information for the base process and carbon capture plant is presented in Table 64. A diagram of the capture process containing further information is provided in Appendix A.

Table 64. Polymeric Membrane – EfW Configuration summary

Item	Description
Base Process Plant	**Existing EfW plant (not new build)**
Waste treatment capacity	350,000 tpa of Municipal Solid Waste (MSW)
Power output	29 MW gross electrical output 25 MW net electrical capacity without carbon capture 11 MW net electrical capacity with carbon capture
Flue gas output	237 tph 12 mol% CO_2
Flue gas treatment	SNCR to control NO_X Acid-gas scrubbing to control SO_X Activated carbon injection to control heavy metal emissions Bag filters to control particulates
Carbon Capture Plant	**Post Combustion Polymeric Membrane**
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure Acid gas abatement, conducted in a section of the direct contact cooler column Direct contact cooler to reduce temperature
Capture	Primary membrane for bulk separation of CO_2 Secondary membrane for concentration of CO_2 from primary membrane
Compression	Single compression train
Conditioning	Cryogenic CO_2 separation unit including refrigeration, CO_2 distillation column, CO_2 pumps and regasification equipment
CO_2 capture level	60% of CO_2 emissions from flue gas during normal operation
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	26 tph (632 tpd) - Liquid phase The CO_2 is generated in the liquid phase because of the cryogenic conditioning equipment used. This would be an advantage for export to higher pressure pipelines as the pressure can be increased by pumping rather than compression. If gas phase CO_2 is required at the export pressure assumed in this scenario, then regasification equipment and additional thermal energy would be required. These additional costs would increase the LCOC.
Steam supply	No steam required from EfW plant during normal operation
Electricity supply	14 MW from EfW plant

15.1.1 Flue Gas Pre-treatment

For capture plants retrofitted to existing EfW plants, it is important that the composition of the flue gas is understood and the interface between the capture technology and the existing plant is appropriately designed.

Membrane capture technology has so far been mainly tested on coal power plant flue gas. Useful information will have been obtained during this testing and there are similarities between coal power plant flue gas and flue gas from an EfW. However, there is limited public domain information available on the results of the testing and flue gas from an EfW will contain a broader range of contaminants than flue gas from a coal power plant.

Literature relating to membrane capture technology indicates that the membranes are tolerant to SO_X and NO_X [34]. However, abatement of these components is still required to allow the CO_2 produced to meet the required specification. In this scenario additional acid gas abatement is provided using an alkali reagent in a section of the direct contact cooler. Oxygen and nitrogen entrained in the CO_2 stream that emerges from the membranes are separated from the CO_2 in the cryogenic CO_2 upgrading process downstream of the membranes.

In the membrane scenario increased cooling of the flue gas is conducted in the direct contact cooler relative to the benchmark scenario. The purpose of the additional cooling is to reduce the power consumption of the compression stages prior to the membranes.

Like with other capture technologies, the performance of the component that enables the separation will be key to its future viability. Testing of membranes using representative flue gas would reduce uncertainty in relation to membrane plant performance when capturing CO_2 from EfW flue gas.

15.1.2 Energy Requirements

Membrane capture of CO_2 is a pressure-driven process that does not require thermal energy. Therefore, there is no requirement for steam to be extracted from the steam system of the host facility in this scenario. This could be an advantage in relation to integration with the host plant as modifications to the existing steam system will not be required.

Electrical energy input to the process is required for a variety of compressors and pumps and the refrigeration required in the CO_2 liquefaction plant. In this scenario electrical energy for the membrane capture plant can be provided from the host EfW plant.

15.1.3 Current Demonstration Status

Membranes are an established separation technology with a variety of commercial applications in different process industries including desalination and removal of H_2S from natural gas. In addition, membranes are used commercially for CO_2 removal from biogas during the production of biomethane. However, the demonstration of membranes in a post combustion application is limited and we are not aware of any testing using flue gas from an EfW facility.

Membrane Technology and Research (MTR's) first-generation Polaris technology has been tested at a capture scale of 20 tpd of CO_2 for over 900 hours using flue gas from coal combustion. The testing was conducted at the National Carbon Capture Center in Alabama from 2010 to 2015 [35].

A larger scale pilot test will be deployed at the Wyoming Integrated Test Center (WITC) in which 140 tpd of CO_2 is expected to be captured. This project is targeting a 70% capture level from a slipstream of flue gas provided by the nearby Dry Fork coal power plant, owned by Basin Electric [36].

Initial engineering design has been carried out by the Electric Power Research Institute (EPRI) for a membrane-based post combustion capture project based at the 600MWe, coal-fired, East Bend Power Station in Boone County, Kentucky. The project was funded by the US Department of Energy (DOE) and was based on MTR's second-generation Polaris membrane technology [37].

15.1.4 Technology Development

Membranes have succeeded in industries where the performance of the membranes used allows the system to outperform other separation technologies. Therefore, membrane performance is a key area for the development of membrane-based post combustion capture systems. Key aspects of membrane performance are detailed below. When membranes are being developed there is often a direct trade-off between these characteristics.

- Flux – the ratio of permeate flow to membrane surface are for a given pressure drop across the membrane. A higher flux means less membrane area is required to produce the same volume of product.
- Selectivity – the ratio of concentration of product in the permeate to the concentration of product in the feed. High selectivity means a purer product may be obtained and or fewer membrane stages used.
- Recovery – the ratio of product in the permeate to product in the retentate. A high recovery rate in a capture application would mean a higher CO_2 capture level in a specific membrane stage.
- Specific cost – derived from the initial purchase cost and the unit lifespan under representative conditions.

Testing of membranes under representative conditions would reduce uncertainty relating to performance and allow new developments to be made. A membrane testing program could include existing membranes that have been developed for other applications, existing membranes with incremental improvements and new types of membrane.

Capture level is another important area for technology development in membrane-based capture systems. In isolation membrane technology is not suited to achieving high capture levels due to increasing costs. For example, MTR's membrane capture process is most efficient at capture levels of between 50 to 70%. To achieve capture levels of 95% or greater, as is likely to be required to meet net zero targets, membranes would need to be used in combination with another capture technology. The requirement to have two capture technologies to achieve a high capture level may add cost and will add complexity to projects.

Hazards

Hazards associated with solvent and solvent degradation products are eliminated in this scenario as there are no chemical reactions involved in the capture process.

CO_2 from the membranes is upgraded using a cryogenic process. This introduces hazards associated with processing of low temperature fluids and pressurised systems.

As with the benchmark scenarios, there are hazards associated with the transportation and storage of CO_2.

Maintenance

The membranes at the core of the capture process have no moving parts, which is an advantage in relation to maintenance. However, membrane units will degrade and have a limited lifespan. Degradation rates will depend on the membrane used and the effectiveness of upstream contaminant removal.

In a membrane capture system, the ancillary equipment includes an array of pumps, compressors, and heat exchangers. This will include compression systems prior to the membranes, vacuum pumps downstream of the membranes and multistage compression trains. While the maintenance requirements of this equipment are generally well understood, understanding the details of the capture plant configuration with respect to redundancy and availability will be important in relation to understanding maintenance requirements. Knowledge gained from operating membrane separation systems in other industry sectors could be applied.

It is possible that modifications may need to be made to existing flue gas treatment equipment to allow the capture plant to interface with the existing EfW plant. If a capture plant is to be retrofitted to an existing EfW any changes to the maintenance requirements for the main process plant should be considered during the design process.

15.2 Cost Summary

Table 65 and Table 66 contain a summary of the capital and annual operational costs for the capture plant.

Table 65. Polymeric Membrane – EfW Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£2.8m
Capture Technology	£56.3m
Compression and conditioning (included in Capture Technology cost)	£0.0m
Auxiliary Systems	£23.7m
Civil works (included in Capture Technology cost)	£0.0m
Total EPC	**£82.8m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.8m
Consultancy	£0.8m
Planning & Other Regulatory	£1.7m
Developer's Costs	£5.8m
Start-Up & Commissioning	£4.1m
Total Project Development	**£13.4m**
Total Capital Cost	
Total Capital Cost	£96.1m
Contingency	10%
Grand Total CAPEX	**£105.7m**

Table 66. Polymeric Membrane – EfW Average annual Operational cost

Item	Cost
Fixed Costs	
Labour	£1.0m
Administration and other overheads	£1.6m
Maintenance	£2.6m
Total fixed OPEX	**£5.2m**
Variable Costs	
Electricity	£7.0m
Steam supply	£0.0m
Membrane	£1.0m
Other chemicals and consumables	£0.1m
Wastes	£0.3m
Plant auxiliary	£0.2m
Total variable OPEX	**£8.5m**
Total Operating Cost	
Total Operating Cost	£13.7m
Contingency	10%
Grand Total OPEX	**£15.0m**

15.3 Key Outputs

Table 67 contains a summary of values relating to the LCOC.

Table 67. Polymeric Membrane – EfW Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.2 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	4.9 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	1.8 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£105.7m	
Total annual OPEX	£15.0m	
Lifetime cost	£481.7m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£236.6m	Adjusted lifetime cost value based on discount rate.
LCOC	**£129/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 37.

Figure 37. Polymeric Membrane – EfW LCOC

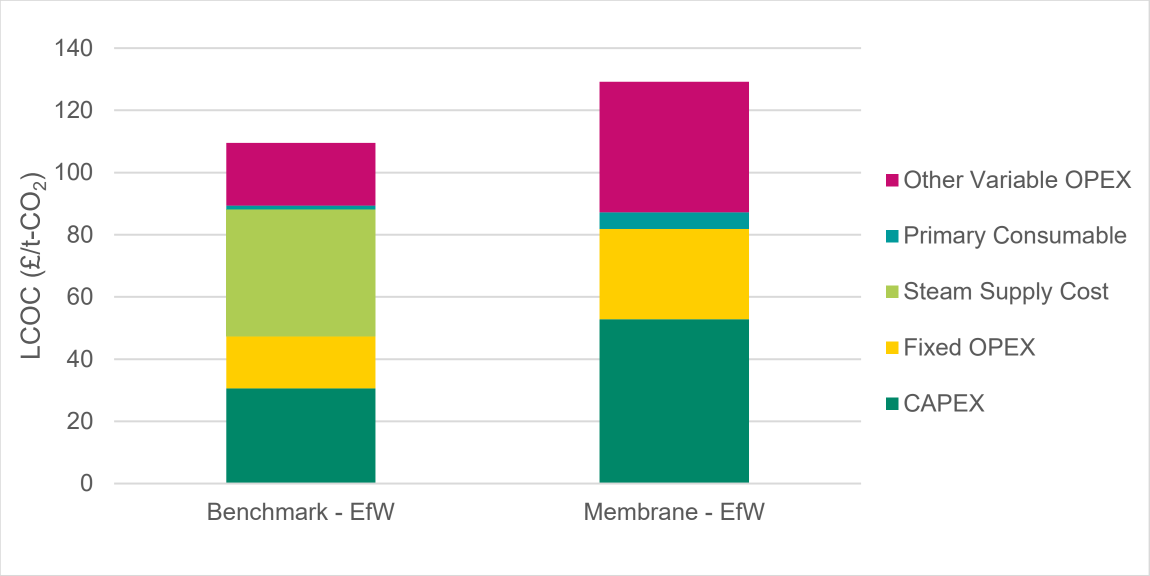


Figure 37 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the benchmark and 60% for the membrane scenario. With the assumed CO_2 emission prices, residual emission costs and hence the impact on product cost, will be higher if capture levels are lower.
3. Both scenarios produce pipeline grade CO_2. In the membrane scenario, it is produced in liquid phase.
4. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The capture level in this scenario is lower than the benchmark. This may present consequential issues in a net zero business environment. Higher capture levels could be achieved by adding an additional capture technology. Membrane cost reductions or performance improvements would improve the LCOC results obtained using membrane technology.

Table 68 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 68. Polymeric Membrane – EfW Impact on product cost

Item	Value	Comment
Product produced	Decarbonised residual waste treatment	
Lifetime mass of waste treated	8.75 Mt	
Lifetime CO_2 captured	4.9 Mt	
LCOC	£129/t	From calculations above
Lifetime CO_2 residual emissions	3.3 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£45.2m/year	Based on the assumed CO_2 emissions price and capture level.
Product market price	£100.3/t-MSW	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£173/t-MSW +£72/t-MSW +72% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£223/t-MSW +£122/t-MSW +122% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£295/t-MSW +£195/t-MSW +194% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£406/t-MSW +£306/t-MSW +305% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

With the assumed CO_2 emission prices, the impact on product cost is higher in technology scenarios with lower capture levels. This is due to the relatively high cost of emitting residual CO_2 to the atmosphere. If CO_2 emission prices were lower, then a solution offering an attractive LCOC, but with a lower capture level, may give a lower cost of product.

15.4 Modelling Assumptions

Table 69 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* report conducted as part of this assignment.

Table 69. Polymeric Membrane – EfW Summary of assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	High	Medium	Medium	The limited scale of pilot plants and the lack of operation on EfW flue gas creates uncertainty in relation to operation with high availability at the modelled scale.
Input gas composition	See Appendix B	Medium	Medium	High	Performance on treated EfW flue gas remains to be demonstrated.
Overall capital cost	See Table 65	Medium	Medium	High	Information on membrane cost is limited and the lack of representative examples creates uncertainty in relation to capital cost. It should be noted that capital costs may be higher or lower than assumed in the scenario.
Maintenance	See Table 66	Medium	Medium	High	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost.
Electricity consumption	See Table 66	Medium	Medium	High	Electricity consumption levels will depend on the performance of the membranes used.
Steam consumption	See Table 66	NA	NA	NA	No steam is required at the plant
Steam price	See Section 9.1.2	NA	NA	NA	No steam is required at the plant
Input gas pre-treatment	See Table 64	Medium	Low	Low	Membranes are understood to have strong resilience to some of the acid gas contaminants in the target flue gas. However, EfW flue gas contains a wide range of contaminants and there is uncertainty relating to the pre-treatment measures required to control membrane degradation.
CO_2 conditioning	See Table 64	Medium	Medium	High	The cryogenic CO_2 conditioning process required to remove non-condensable gases from the CO_2 produced is more onerous than the conditioning systems for some other capture technologies. If gas phase CO_2 is required, rather than liquid phase, then additional equipment and thermal energy will be required.

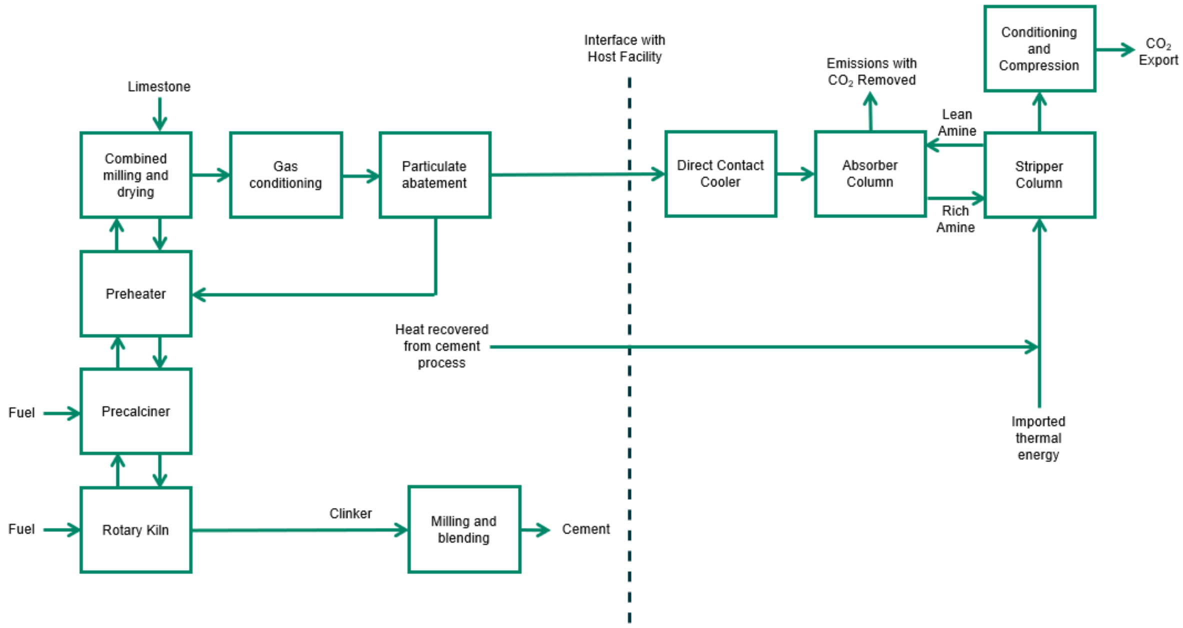
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. Membrane technology has potential advantages in relation to not requiring thermal energy or fuel input, reduced chemical usage, modular construction, and operational flexibility. Testing on representative flue gases is required to develop membrane units and validate cost and performance assumptions.

16. Cement Benchmark

16.1 Description of Scenario

This scenario involves retrofitting an existing 1 Mtpa clinker, cement plant with an amine-based carbon capture plant to produce low carbon cement. Figure 38 shows a block flow diagram of the process.

Figure 38. Block Diagram Cement Plant with Amine Capture



Clinker is the main ingredient of cement and is the component that is most energy and CO_2 intensive to produce. The clinker produced by cement works can be mixed with different supplementary cementitious materials to produce different types of cement. This study focuses on the production of clinker.

The benchmark scenario uses 35% w/w MEA solution as a solvent. Performance information is available for this solvent, and the solvent can be sourced from a variety of suppliers. It is appropriate as a benchmark because its performance is known. However, leading suppliers of amine solvent capture plants will generally offer a proprietary amine blend solvent with claims of improved performance. Advanced amine systems including proprietary solvents and anticipated process developments have been included as scenarios in this analysis for gas fired power generation and EfW to illustrate how future iterations of this technology may perform. Similar improvements relative to the benchmark could be anticipated in the cement sector.

A summary of technical information for the base process and carbon capture plant is presented in Table 70.

Table 70. Cement Benchmark - Configuration summary

Item	Description
Base Process Plant	**Existing cement manufacturing site**
Plant capacity	1 Mtpa clinker (approximately 10% of UK capacity)
Fuels used	Coal c.40% of thermal energy input Alternative waste fuels c.60% of thermal energy input Fuel mix is based on assumed future usage; current mix is typically 50% coal.
Flue gas output	409 tph 18 mol% CO_2
Flue gas treatment	SNCR to control NO_X Gas conditioning tower for cooling Acid gas abatement Bag filters and or electrostatic precipitator for particle abatement
Carbon Capture Plant	**Amine solvent-based carbon capture on flue gas**
Additional flue gas pre-treatment for capture plant	Potential limited modifications to existing acid-gas abatement system to reduce SO_X Flue gas blower to increase pressure and allow admission into downstream process units Direct contact cooler to reduce temperature, with additional caustic treatment for SO_X reduction
Capture	Packed bed absorber with water wash prior to discharge Packed bed stripper column Basic thermal integration of stripper and absorber columns Steam powered reboiler on stripper column Single stage thermal reclaiming
Compression	Single compression train
Conditioning	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
Solvent	35% w/w Monoethanolamine (MEA)
CO_2 capture level	95% of CO_2 emissions from flue gas during normal operation Greenhouse gas emissions from capture plant energy imports are not included.
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	104.2 tph (2500 tpd)
Steam supply	116 MW imported from external source This steam use represents the overall heat load of the capture plant
Electricity supply	13 MW imported from external source

16.1.1 Flue Gas Pre-treatment

For capture plants retrofitted to existing cement plants, it is important that the composition of the flue gas is understood and the interface with the existing plant is appropriately designed. The level of additional treatment required will be site specific and depend on factors including the feedstock used, the emissions abatement system already in place and the requirements of the proposed capture technology.

For contaminants including particulates, heavy metals and volatile organic compounds, it has been assumed that the abatement measures included in the host process plant will be relied upon. The long-term impact of trace contaminants on solvent performance is an area of uncertainty and the subject of ongoing research.

Two important parameters to consider in relation to flue gas pre-treatment are NOx and SO_X, details are provided below.

Oxides of Nitrogen – NO_X

Oxides of nitrogen react with amine solvent and cause the solvent to degrade. Of particular concern is NO_2, which reacts to form nitric acid and subsequently heat stable salts. It has been suggested that the concentration of NO_2 in flue gas should be restricted to approximately 41 mg/Nm^3 (20 ppmv at 6% O_2) for economic post-combustion capture using amine [18].

The reference flue gas for the cement benchmark has a NO_X concentration of 250 mg/Nm^3. If 10% [38] of the NO_X is NO_2 this gives a NO_2 concentration of 25 mg/Nm^3 (12ppmv at 6% O_2). On this basis no further NO_X control would be needed prior to an amine capture plant based on this input gas specification. However, it is noted that some projects that are developing carbon capture for EfW plants assume that additional SCR will be installed as part of the capture plant retrofit, based on specific flue gas conditions and proprietary solvent performance. Additional NO_X abatement may also be required at sites in the cement industry.

Oxides of Sulphur - SO_X

Oxides of sulphur also react with amine solvent causing it to degrade. It has been suggested that the concentration of SO_2 in flue gas should be restricted to approximately 29 mg/Nm^3 (10 ppmv at 6% O_2) for economic post-combustion capture using amine [39].

SO_X emissions from fuel combustion are largely controlled by contact with the feed material in the preheaters. For cement plants where the feedstock does not contain oxidisable sulphur SO_X emissions will be negligible. However, if sulphur containing components such as pyrite or marcasite are present in the feed then some form of flue gas desulphurisation may be required.

The reference flue gas for the cement benchmark has a SO_X concentration of 25 mg/Nm^3. If 95% [20] of the SO_X is SO_2, this gives a SO_2 concentration of 24 mg/Nm^3 (8 ppmv at 6% O_2). On this basis no further SO_X control would be needed prior to an amine capture plant based on this input gas specification.

If further control of SO_X is required, on some plants it will be possible to achieve this by modifying existing flue gas desulphurisation equipment. If significant upgrades are required or the installation of a new flue gas desulphurisation this may make the use of solvents or other capture technologies that are more resilient to SO_X more attractive at a particular site.

16.1.2 Thermal Energy

Unlike in the gas power generation or EfW cases it is not possible to extract the required quantity of thermal energy from the main process plant in the cement benchmark case. The challenges associated with the provision of thermal energy may influence the technology selected for future capture projects in the cement industry by increasing the attractiveness of capture technologies that require less thermal energy or do not require any thermal energy.

It is possible to recover an amount of useful heat from the cement manufacturing process. Opportunities for heat recovery arise when material cools after the rotary kiln or when flue gases are cooled during the emissions treatment process. However, the amount of heat available will vary between sites and the feasibility of accessing the heat needs assessed on a case-by-case basis with respect to constraints such as space for equipment and accessibility. In any case, the amount of thermal energy available will not be sufficient to operate an amine-based capture plant to capture 95% of CO_2 present in the cement plant flue gas.

It is assumed that a low carbon source of thermal energy will be required for the capture plant. The economic viability of capture technology relies on a suitably high cost being applied to emission of CO_2 to the atmosphere. If the cost of emitting CO_2 to the atmosphere is low enough to allow the use of unabated fossil fuel combustion to supply heat to large industrial heat users, then the capture plant itself may be unviable.

There are several options available for supplying the additional low carbon thermal energy required to operate an amine-based capture plant at a cement manufacturing facility. These include biomass combustion, electricity from low carbon sources, low carbon hydrogen, fossil fuels with carbon capture, nuclear, geothermal, or heat from a neighbouring industrial process. The most suitable source of thermal energy will vary between locations depending on what resources are available. Comparison of low carbon heat options is not the focus of this study.

There are a variety of challenges associated with these energy sources. These include high unit costs, intermittency, CO_2 emissions, resource availability, land use or the creation of complex wastes. If a good source of low carbon energy is found for a particular site it would also be worth investigating whether it could be directly used in the cement manufacture process. This could allow reduced use of coal as a primary fuel to provide thermal energy to plant. Although, it would not address CO_2 emissions of associated with the calcination of limestone in the cement manufacture process.

While the use of waste derived fuels has increased in recent years, coal combustion still provides a significant portion of thermal energy provision in the UK cement industry. Increased support for the use of biomass and / or waste derived fuels in the cement industry could help reduce carbon emissions from the sector. The use of biomass derived fuels has been subsidised, and contributed to decarbonisation, in the power generation and domestic heat sectors.

Table 71 details assumptions relating to the provision of thermal energy for the cement benchmark. However, it should be noted that there may be some plants which are able to access steam with a lower unit cost than has been assumed.

Table 71. Thermal energy assumptions for cement benchmark

Item	Value	Comment
Heat recovery available from 1 Mtpa clinker manufacturing process.	6.3 MW	This is approximately equal to 5% of the thermal energy required for the capture plant. The availability of useful thermal energy will vary between cement manufacturing sites.
Unit cost for heat recovered from existing plant.	£6.8 / MW [40]	The unit cost of recoverable thermal energy will vary between cement manufacturing sites.
Unit cost of alternative energy source	See methodology for annual cost figures	As described above there is a wide variety of options available for the supply of low carbon heat, each with associated challenges and uncertainties. A specific source of low carbon heat has not been selected from the options available. The cost used is a nominal figure based on the cost of electricity generation (wholesale price) as assumed in the other benchmark cases. This value for the unit cost of steam includes contributions from both capital and operational costs associated with providing the low carbon heat.

None of the scenarios in this study use steam powered drives to operate major items of equipment such as compressors or blowers. This is an option that projects may wish to consider during the engineering design and optioneering phase of project development.

16.1.3 Current Demonstration Status

There are a limited number of operating examples of carbon capture on cement manufacture using solvent capture processes.

The largest demonstration of solvent-based carbon capture in the cement industry to date is at Anhui Conch's Baimashan cement plant in Anhui Province, China. This capture plant has been in operation since 2018 and captures approximately 50,000 tpa of CO_2.

Dalmia Cement announced plans in 2019 to construct a capture plant at their facility in Tamil Nadu, India, with the potential of capturing up to 500,000 tpa of CO_2. There is currently no completion date specified for this project.

A 400,000 tpa of CO_2 capture project is being developed at the existing Norcem cement plant operated by Heidelberg Cement in Brevik, Norway. This project was approved in 2020 and is expected to begin operation in 2024. Aker Solutions technology will be used. The Norcem Brevik project uses only thermal energy recovered from the cement manufacturing process to operate the capture process. However, the project is designed for a lower capture level than the benchmark in this study. Around 50% of annual CO_2 emissions are captured by treating part of the flue gas flow from the facility. A higher amount of thermal energy is available for recovery at the Norcem Brevik facility due to dry feedstock and the proposed capture technology has a lower heat demand than conventional amine capture [41]. Thus, for typical UK Cement plants the capture level achievable from waste heat alone is likely to be significantly lower than at Brevik, and far below the target 95%.

16.1.4 Technology Development

Areas for technology development in relation to the application of amine solvent capture technology in the cement industry are outlined below:

- Identification and development of sources of low carbon heat to provide the thermal energy required.

- An improved understanding of solvent management when exposed to cement plant flue gases.
- Demonstration of long-term reliable operation to reduce cost and performance uncertainty and build investor confidence.
- Standardisation of designs and improving construction techniques to allow cost reductions.

Carbon capture with a high capture level will ultimately be needed to allow a cement plant to operate with very low CO_2 emissions. However, if a phased approach is taken to CO_2 emission reduction in the sector then in the short to medium term carbon capture projects will be required to compete with other decarbonisation options, such as reducing the proportion of coal in the fuel mix.

Hazards

As in the gas power generation benchmark, the main new hazards of this technology are the transport and storage of CO_2, and the release of solvents and or potentially harmful solvent degradation products into the environment. Mitigation measures are available to reduce the risk of harm resulting from these hazards.

While not directly relating to the capture technology, the location of cement plants near feedstock sources rather than in industrial centres, may result in increased transportation of CO_2. Increased CO_2 transportation distances will increase the hazard associated with CO_2 transportation.

Any change to the emissions from the plants has the potential to impact public perception of the technology. We would expect that reducing CO_2 emissions using capture technology to be viewed positively. However, the introduction of any new potentially harmful emissions, such as amine degradation products, risks inviting negative attention.

Maintenance

Maintenance requirements for amine-based post combustion capture in a gas fired power generation application are described in Section 6.1.4. Requirements when the technology is applied to the cement sector will be similar.

For cement plants there will be additional maintenance requirements relating to:

- Heat recovery equipment used to recover heat from the cement manufacturing process.
- The system used to provide the remaining thermal energy required by the capture plant.
- Additional flue gas pre-treatment equipment and or modifications to the existing emissions abatement equipment at the main process plant.

16.2 Cost Summary

Table 72 and Table 73 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 72. Cement Benchmark - Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£3.6m
Capture Technology	£32.5m
Conditioning	£1.7m
Compression	£5.8m
Auxiliary Systems	£79.8m
Civil works	£27.3m
Total EPC	**£150.6m**
Project Development Costs	
Land Requirements	£0.3m
Utility & Infrastructure Connections	£1.5m
Consultancy	£1.5m
Planning & Other Regulatory	£3.0m
Developer’s Costs	£10.5m
Start-Up & Commissioning	£7.5m
Total Project Development	**£24.4m**
Total Capital Cost	
Total Capital Cost	£175.0m
Contingency (10%)	10%
Grand Total CAPEX	**£192.5m**

Table 73. Cement Benchmark – Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration and other overheads	£2.9m
Maintenance	£4.8m
Total fixed OPEX	**£8.6m**
Variable Costs	
Electricity	£11.8m
Steam supply	£55.8m
Solvent	£1.8m
Other chemicals and consumables	£1.2m
Wastes	£1.8m
Plant auxiliary	£0.2m
Total variable OPEX	**£72.7m**
Total Operating Cost	
Total Operating Cost	£81.3m
Contingency	10%
Grand Total OPEX	**£89.4m**

16.3 Key Outputs

Table 74 contains a summary of the values relating to the LCOC.

Table 74. Cement Benchmark - Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.8 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	19.4 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	7.2 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£192.5m	
Total annual OPEX	£89.4m	
Lifetime cost	£2,428.4m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£1007.7m	Adjusted lifetime cost value based on discount rate.
LCOC	**£139/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 39.

Figure 39. Cement Benchmark LCOC

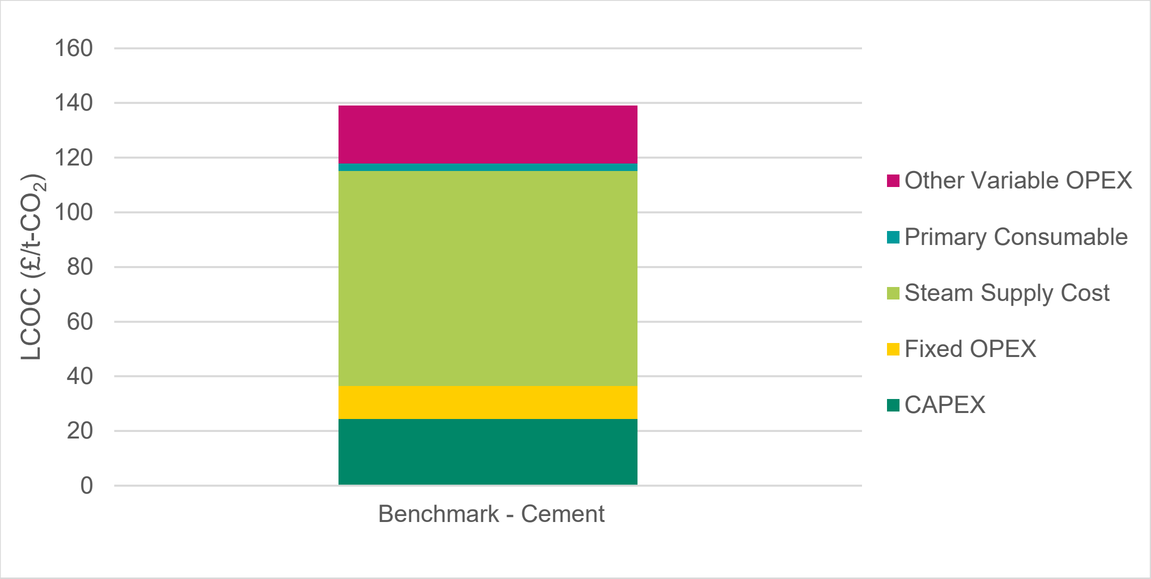


Figure 39 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95%.
3. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

Table 75 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 75. Cement Benchmark - Impact on product cost

Item	Value	Comment
Product produced	Decarbonised clinker	
Lifetime mass of clinker produced	25 Mt	
Lifetime CO_2 captured	19.4 Mt	
LCOC	£139/t	From calculations above
Lifetime CO_2 residual emissions	1.0 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£14.1m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64.5/t-clinker	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£172/t-clinker +£108/t-clinker +167% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£78/t-clinker +£13/t-clinker +21% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£186/t-clinker +£121/t-clinker +188% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£332/t-clinker +£267/t-clinker +414% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

16.4 Modelling Assumptions

Table 76 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 76. Cement Benchmark – Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	High	Medium	Medium	Cement plants are designed for continuous high load operation to maximise asset utilisation. The presence of contaminants in the flue gas creates a risk in relation to availability. However, with sufficient flue gas pre-treatment, and effective solvent management, operation with high availability should be possible.
Input gas composition	See Appendix B	High	Medium	Medium	Over the life of the capture plant the fuel mixture used at the cement plant could change. The use of lower carbon energy sources such as hydrogen or electricity to provide thermal energy in the cement plant would alter the composition of the flue gas and could impact the economics of the capture plant.
Overall capital cost	See Table 72	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to capital cost. In addition, there is uncertainty relating to plant integration costs. However, overall cost uncertainty is low in comparison to other scenarios in this analysis.
Maintenance	See Table 73	Medium	Low	Low	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost. However, cost uncertainty is low in comparison to other scenarios in this analysis.
Electricity consumption	See Table 73	High	Low	Low	Electrical energy requirements are relatively well known for MEA capture plants with a defined configuration.
Electricity price	See Section 5.4	High	Medium	Medium	In the cement case electricity needs to be imported. For amine capture electricity makes up a lower proportion of the energy input and operating cost than heat.
Steam consumption	See Table 73	High	Medium	Medium	Thermal energy requirements are relatively well known for MEA capture plants. However, thermal energy is the single largest operating cost, so any changes may impact LCOC.
Steam price	See Section 16.1.2	Low	Medium	Very High	Thermal energy is the single largest operating cost for the plant and sufficient low carbon thermal energy is not available from the process. At any specific site the cost of providing the thermal energy required could be significantly higher, or lower, than the assumed value.
Primary consumables (solvent)	See Table 73	Medium	Medium	High	Solvent may degrade faster than expected due to contaminants, leading to greater solvent consumption.
Input gas pre-treatment	See Table 70	Medium	Medium	High	Cement flue gas contains a wide range of contaminants and there is uncertainty relating to the pre-treatment measures required to control solvent degradation.
CO_2 conditioning	See Table 70	High	Medium	Medium	The amine capture process will absorb some of the residual contaminants in the flue gas input stream.

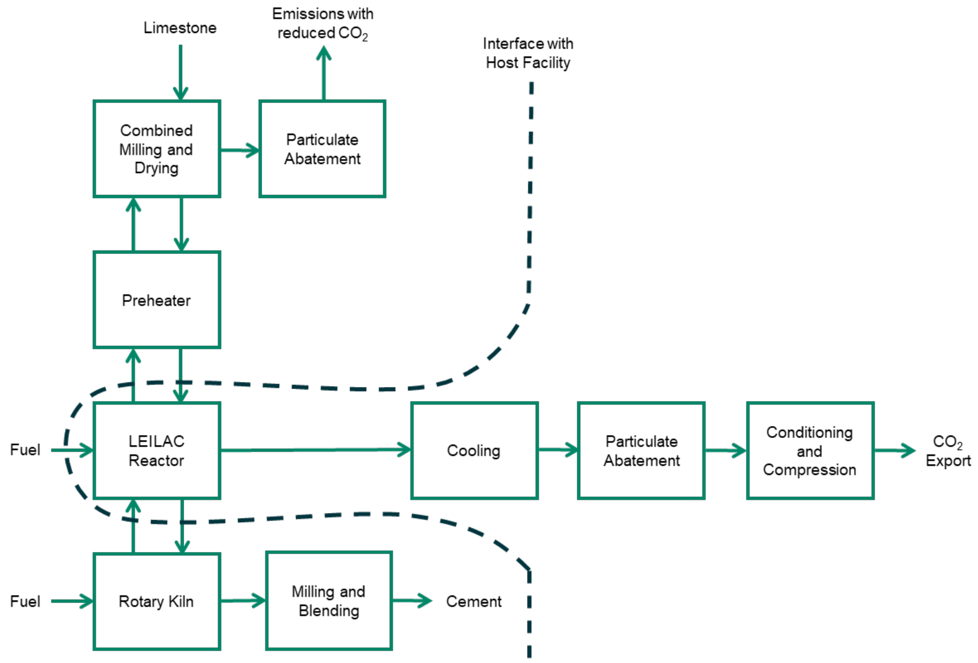
Overall, there is a *medium* level of uncertainty associated with the modelling of this scenario. Integration challenges will be highly site specific when capture technology is retrofitted to a cement plant. The availability of thermal energy with an acceptable unit cost and associated level of CO_2 emissions is a source of uncertainty.

17. Low Emissions Intensity Lime and Cement (LEILAC)

17.1 Description of Scenario

This scenario involves retrofitting an existing 1 Mtpa clinker, cement plant with a Low Emissions Intensity Lime and Cement (LEILAC) reactor to aid capture at the site. The LEILAC process is a form of calcination technology that aids carbon capture, rather than a post combustion capture technology. This distinction is important when comparisons between technologies are being made. Figure 40 shows a block flow diagram of the process, with the dashed line representing the interface between the existing cement plant and the new equipment required for capture.

Figure 40. Block Diagram – Cement plant using the LEILAC process



The LEILAC process can be used instead of a traditional precalciner in cement manufacture. CO_2 is produced in cement production when calcium carbonate (limestone) is heated and becomes calcium oxide (lime). Typically, this CO_2 is mixed with combustion gases in the precalciner and emitted to the atmosphere with the flue gas. In the LEILAC process, powdered calcium carbonate passes through an externally heated tubular reactor. This reactor is sometimes referred to as a direct separation reactor (DSR). The separation of the heat source and chemical reaction in the LEILAC process allows the CO_2 liberated to be collected in a relatively pure form (c.95%), making it easier to capture.

A stated advantage of LEILAC process is that chemicals, such as solvents or sorbents, are not required for the main part of the capture process. Additional energy requirements are low if the technology is viewed as a replacement for a conventional precalciner and the energy use of a conventional precalciner is discounted against the energy use of the LEILAC process. This assumption has been made in this study.

This study assumes that the cost of the new LEILAC process has been included as it is a retrofit project. In a new build, or if the existing precalciner was due for replacement, then it may be reasonable to discount the cost of a conventional precalciner against the cost of the LEILAC process. This would lower the associated cost penalty of the capture.

The LEILAC process potentially allows lower cost capture of CO_2 emissions generated during cement production. However, the reactor only captures CO_2 from the calcination stage of the process (around 60% of the total emissions) and not emissions from the combustion of fuels. If a higher overall capture level is required a further carbon capture technology would have to be added to capture the combustion emissions. Waste heat to operate a post combustion capture system may be available from the cement manufacturing process.

A summary of technical information for the base process and carbon capture plant is presented in Table 77. A diagram of the capture process containing further information is provided in Appendix A.

Table 77. LEILAC Process – Cement Configuration summary

Item	Description
Base Process Plant	**Modified cement manufacturing site**
Plant capacity	1 Mtpa clinker (approximately 10% of UK capacity)
Fuels used	Coal c.40% of thermal energy input Alternative waste fuels c.60% of thermal energy input Fuel mix is based on assumed future usage; current mix is typically 50% coal.
Flue gas output	320 tph 9 mol% CO_2 Note that the mass flow and CO_2 concentration of the flue gas has reduced relative to the benchmark due to the introduction of the LEILAC process.
Flue gas treatment	SNCR to control NO_X Gas conditioning tower for cooling Acid gas abatement Bag filters and or electrostatic precipitator for particle abatement
Alterations to base process plant	Replacement of existing precalciner by LEILAC technology Connections required for cement meal feedstock, fuel supply, combustion air, CO_2 exhaust, electricity, and control.
Processing of CO_2 leaving LEILAC reactor (no emissions from fuel combustion are captured)	
Cooling	Heat exchanger to lower temperature of CO_2 exiting LEILAC reactor
Particulate abatement	Particulate abatement will be required to remove dust entrained in the CO_2 stream. Cyclones followed by bag filters, or an electrostatic precipitator could be used for this purpose.
Conditioning	Conditioning requirements will be different from post combustion technologies because different contaminants will be present, including hydrogen, H_2S, methane and other hydrocarbons. The type and level of contamination will be influenced by the composition of the limestone feedstock used.
Compression	Single compression train
Deoxygenation and dehydration	Deoxygenation Triethylene Glycol (TEG) dehydration – other dehydration technology is available if TEG carryover exceeds pipeline operator requirements. Cooling of CO_2 product
CO_2 capture level	c.60% of CO_2 emissions from original plant during normal operation Combustion emissions are not captured
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	64 tph (1,547 tpd)
Additional fuel supply	0.7 tph of coal and 1.5 tph of RDF supplied to LEILAC reactor
Steam supply	1 MW used for CO_2 conditioning, from host plant recovered waste heat
Electricity supply	6 MW imported from external source

17.1.1 Precalciner Performance

The LEILAC reactor used in this application is a type of precalciner that aids carbon capture. Therefore, the performance of the unit as a precalciner is important. Potential benefits in allowing CO_2 to be more easily captured could easily be negated if the unit were to perform poorly as a precalciner. Performance parameters to consider for a precalciner include:

- The ability to produce a material that meets the required specification for downstream equipment. This will include achieving a sufficient level of calcination when operating at full load.
- Flexibility to operate with cement meal feedstock of a range of qualities that are representative of that available at target installation sites.
- Availability, noting that downtime may impact the cement manufacturing facility and not just the capture of CO_2.
- Long term maintenance requirements.
- Start-up and shutdown requirements.
- Energy use – to be considered in conjunction with potential energy savings in associated carbon capture equipment.
- Capital cost - to be considered in conjunction with potential capital cost savings in associated carbon capture equipment.

Performance of the LEILAC process in relation to many of the above parameters remains to be demonstrated due to the stage of development of the technology. The LEILAC 2 project being developed by CALIX in intended to provide performance data and validate performance assumptions.

If LEILAC technology is to be retrofitted to existing plants understanding integration challenges will also be important. The use of LEILAC technology may have implications for equipment in several other areas of the cement plant. The technology may not be suitable for retrofit at some sites due to space or layout restrictions. In addition, the age and condition of the cement plant and existing precalciner equipment will be important factors to consider in retrofit projects.

17.1.2 Thermal Energy

The LEILAC process uses energy released from the combustion of fuels to provide the heat necessary to drive the chemical reaction that takes place inside the reactor. If the process works well the energy requirements could be expected to be of a similar magnitude to the energy requirements for conventional precalciner equipment. However, there will be an energy penalty associated with not having direct contact between the combustion gases and the material to be heated. Energy requirements for the LEILAC process remain to be validated in commercial operation.

In the model created, the energy penalty associated with using a LEILAC reactor, rather than a conventional pre-calciner, is met by the combustion of additional solid fuel. Combustion emissions from the fuel required by the cement plant, or the additional fuel used by the LEILAC process relative to conventional precalciner equipment, are not captured in this scenario.

The LEILAC 1 pilot project used natural gas to provide the energy required for the reactor. The planned LEILAC 2 project intends to demonstrate the ability of the equipment to operate on a variety of fuels. Combustion of some solid fuels, including refuse derived fuel, can be technically complex. Details of the proposed burner arrangement and the range of fuels which the burner will be able to operate on have not been reviewed.

In a traditional clinker manufacturing process, the hot CO_2 evolved from the limestone would immediately mix with combustion gases in the pre-calciner. The thermal energy in this mixture of gases would be used in the downstream cement meal pre-heaters. If a LEILAC reactor is used, the high temperature CO_2 (around 700°C) will exit the process in a separate stream. Cooling of this stream will be required, potentially using a heat recovery steam generator , with the steam generated being used to meet process needs or generate electricity if appropriate equipment is installed.

For carbon capture, energy input is required into the LEILAC reactor and in relation to the conditioning and compression of the CO_2 stream produced by the LEILAC process. It is reasonable to subtract the energy that would have been used by an alternative precalciner, when estimating energy requirements for carbon capture.

This allows a comparatively low energy penalty to be associated with the carbon capture and is a potential selling point for the technology. However, it is important to remember that the energy consumption figures generated are not directly comparable to those of post combustion capture technologies. The LEILAC reactor is a precalciner technology that aids carbon capture and not a post combustion capture technology.

17.1.3 Current Demonstration Status

Calix's LEILAC technology was tested during the LEILAC1 project as part of the EU's Horizon 2020 Research and Innovation programme. A pilot project was constructed with a rating of c.25 ktpa of CO_2 capture in Lixhe, Belgium. While the concept was demonstrated some important performance parameters including availability and calcination level at high throughput remain to be validated.

The LEILAC2 project, also supported by the EU Horizon 2020 Research and Innovation programme, involves the construction of a c.100 ktpa demonstration project. The project will be based in Germany and is targeted to be operational by 2023.

17.1.4 Technology Development

Areas for development of the LEILAC technology include the following:

- Validate capital costs and key performance parameters in a representative environment through construction of demonstration facilities. Demonstrating overall efficiency and impact on clinker quality are aims of the LEILAC 2 project.
- Practical demonstration of the use of different energy sources to operate the LEILAC technology. These could include refuse derived fuels, biomass, hydrogen, and electricity. The LEILAC 1 project was operated on natural gas. One of the objectives of the LEILAC 2 project is to provide practical demonstration of the use of various energy sources.
- Demonstrate use of the technology in new applications. Other DSR technologies have been used to produce magnesium oxide and other mineral products. Development work is taking place in relation to DSR use in the iron and steel sector and other applications may exist.

Hazards

In this application, the LEILAC reactor is a precalciner technology and has hazards comparable to other precalciner technologies. These will include high temperature operation and processing of a hazardous powder (calcium oxide / lime). The LEILAC process will also have hazards associated with the handling and combustion of fuel.

The hazard associated with the release of solvents and potentially harmful solvent degradation products is eliminated in this scenario as there is no solvent used.

Maintenance

Areas of plant requiring maintenance will include.

- Materials handling equipment before and after the LEILAC reactor. Much of this will be like more conventional precalciner technology.
- Combustion equipment, with maintenance requirements varying depending on the fuel used.
- The core LEILAC tubular reactors.
- Particulate abatement equipment required for CO_2 processing.
- Downstream CO_2 conditioning and compression equipment, similar to other capture technologies.

Prior to the construction of a facility that operates on a continuous basis there is uncertainty associated with maintenance costs and requirements.

17.2 Cost Summary

Table 78 and Table 79 contain a summary of the capital and annual operational costs for the carbon capture plant. In a new build plant, or if a replacement precalciner is required, the capital cost for a conventional precalciner could be subtracted from the project cost because the LEILAC process is a replacement for standard precalciner equipment.

Table 78. LEILAC Process – Cement Capital cost

Item	Cost
EPC Costs	
LEILAC Technology	£68.4m
Conditioning	£0.0m
Compression	£3.9m
Auxiliary Systems	£11.3m
Civil works	£3.4m
Total EPC	**£87.0m**
Project Development Costs	
Land Requirements	£0.1m
Utility & Infrastructure Connections	£0.9m
Consultancy	£0.9m
Planning & Other Regulatory	£1.7m
Developer’s Costs	£6.1m
Start-Up & Commissioning	£4.3m
Total Project Development	**£14.0m**
Total Capital Cost	
Total Capital Cost	£101.0m
Contingency	10%
Grand Total CAPEX	**£111.1m**

As the LEILAC process involves a process alteration, the assumed energy consumption of a conventional precalciner has been subtracted from the energy use in this scenario.

Table 79. LEILAC Process – Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.6m
Administration	£1.7m
Maintenance	£2.8m
Total fixed OPEX	**£5.1m**
Variable Costs	
Additional solid fuel consumption	£1.6m
Electricity	£5.3m
Steam supply	£0.0m
Other chemicals and consumables	£0.0m
Wastes	£0.2m
Plant auxiliary	£0.2m
Total variable OPEX	**£7.4m**
Total Operating Cost	
Total Operating Cost	£12.5m
Contingency	10%
Grand Total OPEX	**£13.7m**

17.3 Key Outputs

Table 80 contains a summary of the values relating to the LCOC.

Table 80. LEILAC Process – Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.5 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	12.0 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	4.5 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£111.1m	
Total annual OPEX	£13.7m	
Lifetime cost	£454.4m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£230.5m	Adjusted lifetime cost value based on discount rate.
LCOC	**£51/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 41.

Figure 41. LEILAC Process – Cement LCOC

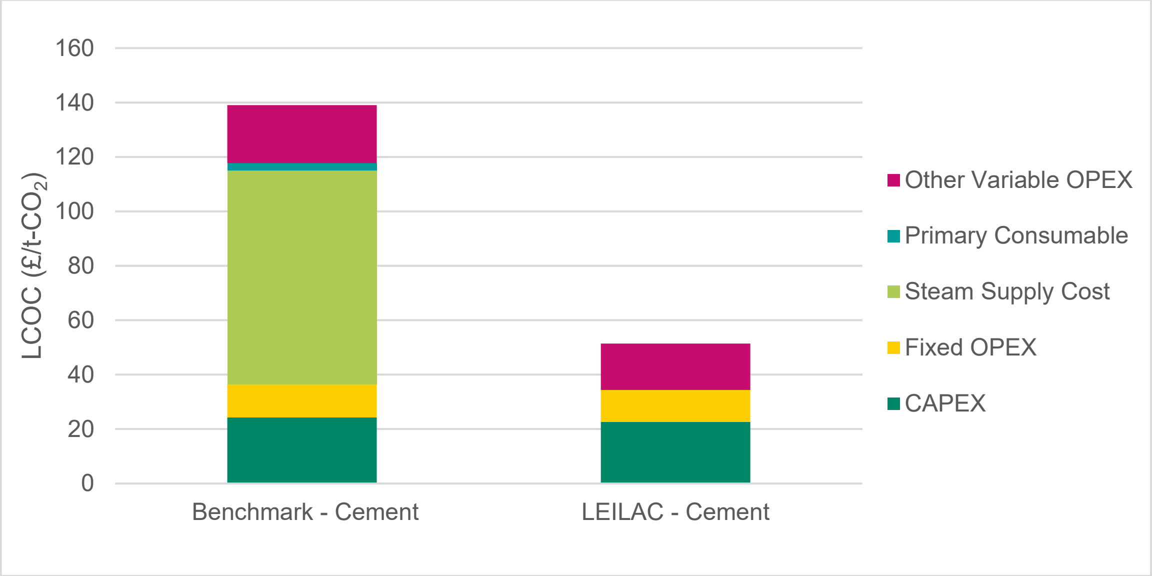


Figure 41. LEILAC Process – Cement LCOC

Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the benchmark scenario and 60% for LEILAC. With the assumed CO_2 emission prices, residual emission costs and hence the overall impact on product cost, will be higher with the lower capture levels of the LEILAC process.
3. The LEILAC process involves a process alteration that aids capture, rather than standalone capture technology. Impacts on the cement manufacturing process may not be reflected in the LCOC values.
4. In a new build plant, or if a replacement precalciner is required, the capital cost for a conventional precalciner could be subtracted from the project cost because the LEILAC reactor is a replacement for standard precalciner equipment. This would lower the LCOC.
5. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The results show a reduction in LCOC relative to the benchmark. Performance ranges were provided by the technology supplier for some aspects of performance used to derive the LCOC values. If more ambitious figures from the ranges were selected, then there would be a greater reduction in LCOC relative to the benchmark.

The capture level in this scenario is lower than the benchmark and this may be an issue in a net zero business environment. Capture level could be improved by using an additional capture technology, such as a solvent based system, to capture CO_2 from the combustion flue gases. Waste heat from the cement manufacture process could contribute to the energy requirements of the additional capture technology.

Table 81 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 81. LEILAC Process – Impact on product cost

Item	Value	Comment
Product produced	Decarbonised clinker	
Lifetime mass of clinker produced	25 Mt	
Lifetime CO_2 captured	12.0 Mt	
LCOC	£51/t	From calculations above
Lifetime CO_2 residual emissions	8.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£116.4m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64.5/t-clinker	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£89/t-clinker +£25/t-clinker +38% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£175/t-clinker +£110/t-clinker +171% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£199/t-clinker +£135/t-clinker +209% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£332/t-clinker +£267/t-clinker +414% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

With the assumed CO_2 emission prices, the impact on product cost is higher in technology scenarios with lower capture levels. This is due to the relatively high cost of emitting residual CO_2 to the atmosphere. If CO_2 emission prices were lower, then a solution offering an attractive LCOC, but with a lower capture level, may give a lower overall cost of product.

17.4 Modelling Assumptions

Table 82 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 82. LEILAC Process – Cement Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Plant availability	85%	Medium	High	Very high	The technology is yet to demonstrate operation with high availability due to its stage of development. If the LEILAC 2 project operates as planned availability uncertainty will reduce. The impact of downtime is greater than in post combustion scenarios because it will impact the cement manufacturing plant and not just the capture process.
Overall capital cost	See Table 78	Medium	Medium	High	Process alteration capture technologies have potential advantages over post combustion technologies in relation to capital cost. However, the performance improvements required, and bespoke nature of the equipment create uncertainty. If the cost of a conventional precalciner was subtracted from the cost of the LEILAC process this would be a saving.
Maintenance	See Table 79	Medium	Medium	High	Process alteration capture technologies have potential advantages over post combustion technologies in relation to maintenance. However, the performance improvements required, and bespoke nature of the equipment create uncertainty.
Electricity consumption	See Table 79	Medium	Low	Low	Electricity consumption is relatively low for the technology.
Electricity price	See Section 5.4	High	Low	Low	Electricity consumption is relatively low for the technology so the economics will not be less sensitive to electricity price changes than other scenarios.
Additional fuel consumption	See Table 79	Medium	Medium	High	Process alteration capture technologies have potential advantages over post combustion technologies in relation to energy input. However, the thermal energy required to operate the LEILAC process with high calcination levels, at high throughput, remains to be validated. In this scenario, CO_2 emissions from additional fuel use in the LEILAC process are not captured.
Primary consumables	NA	NA	NA	NA	Some solvents or sorbents will be used in the final CO_2 conditioning, but overall, the technology has little reliance on solvents or sorbents.
CO_2 conditioning	See Table 77	Medium	Medium	High	The CO_2 stream from the LEILAC reactor will contain a range of contaminants. These may include hydrogen, H_2S, methane and other hydrocarbons. Research into the composition of the CO_2 stream under different operating conditions is ongoing.

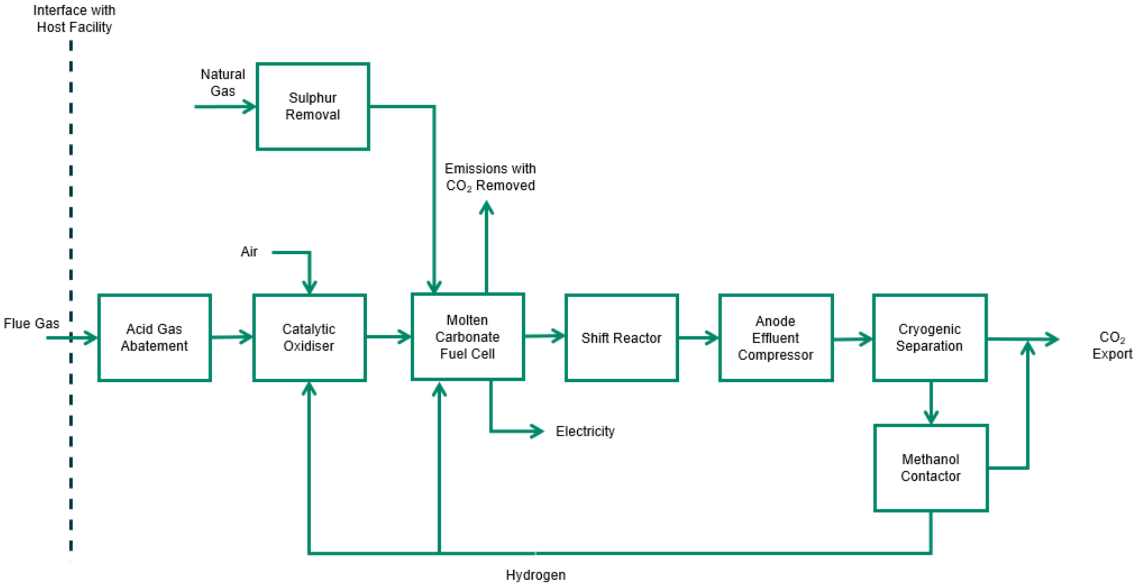
Overall, there is a *very high* level of uncertainty associated with the modelling of this scenario. Process alterations that aid capture have potential advantages in relation to capital and energy costs. However, the anticipated performance for key parameters remains to be demonstrated and any availability issues would also impact cement production. Results from the LEILAC 2 project could reduce performance uncertainty.

18. Molten Carbonate Fuel Cell - Cement

18.1 Description of Scenario

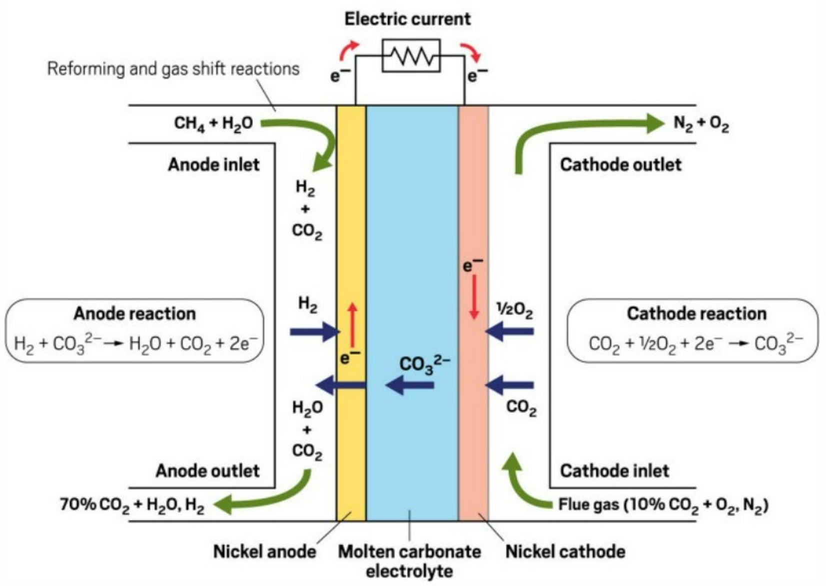
This scenario involves retrofitting an existing 1 Mtpa clinker, cement plant with a molten carbonate fuel cell (MCFC) based post combustion capture process. Figure 42 shows a block flow diagram of the process, with the dashed line representing the interface between the existing cement plant and MCFC capture plant.

Figure 42. Block Diagram – Cement with MCFC capture



A MCFC is an electrochemical device in which CO_2 is reduced to form carbonate ions (CO_3^{2-}) before being oxidised to CO_2. The energy to drive the process is derived from the oxidation of natural gas (CH_4), with electricity also being generated in the process. Figure 43 shows the chemical reactions and capture mechanism within the MCFC.

Figure 43. MCFC carbon capture mechanism [31]



A summary of technical information for the base process and carbon capture plant is presented in Table 83. A diagram of the capture process containing further information is provided in Appendix A.

Table 83. MCFC – Cement Configuration summary

Item	Description
Base Process Plant	**Existing cement manufacturing site**
Plant capacity	1 Mtpa clinker (approximately 10% of UK capacity)
Fuels used	Coal c.40% of thermal energy input Refuse derived fuel c.60% of thermal energy input Fuel mix is based on assumed future usage; current mix is typically 50% coal.
Flue gas output	409 tph 18 mol% CO_2
Flue gas treatment	SNCR to control NO_X Gas conditioning tower for cooling Acid gas abatement Bag filters and or electrostatic precipitator for particle abatement
Carbon Capture Plant	**Post Combustion MCFC**
Power output	69.7 MW net electrical output (from MCFC)
Additional flue gas pre-treatment for capture plant	Flue gas blower to increase pressure Limestone flue gas desulphurisation to further reduce SO_X Bag filters to further reduce particulates Catalytic oxidation to oxidise residual H_2 and CO
Capture	Desulphurisation of natural gas fuel input Molten carbonate fuel cell for separation of CO_2 from flue gas Shift reactor to convert residual CO in anode outlet gas Condenser to remove H_2O from anode outlet gas Thermal integration system Steam turbine
Compression	Single compression train
Conditioning	Cryogenic CO_2 separation unit CO_2 separation from hydrogen recycle using methanol contacting
CO_2 capture level	96% of CO_2 emissions from flue gas during normal operation ~100% of CO_2 emissions from natural gas used
Operational hours	7,446 hours/year (8760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	133 tph (3,192 tpd) Liquid phase The CO_2 is generated in the liquid phase because of the cryogenic conditioning equipment used. This would be an advantage for export to higher pressure pipelines as the pressure can be increased by pumping rather than compression. If gas phase CO_2 is required at the export pressure assumed in this scenario, then regasification equipment and additional thermal energy would be required. These additional costs would increase the LCOC.
Natural gas supply	12 tph
Steam supply	No steam required from cement plant during normal operation
Electricity supply	No electricity required from cement plant during normal operation

18.1.1 Flue Gas Pre-Treatment

The MCFC requires lower levels of contaminants in the incoming flue gas than other capture technologies. There will be challenges associated with reliably protecting the MCFC stack against damage from contaminants without incurring excessive equipment costs.

Additional particulate abatement equipment has been included in this scenario. When developing projects using MCFCs, the requirement for additional particulate abatement equipment should be confirmed on a case-by-case basis based on review of existing equipment and input specification for the selected MCFC.

In most EfW plants, additional acid gas removal equipment will be required to reduce SO_X levels to around 0.4 ppmv. A flue gas desulphurisation polishing unit will be required. Due to the low tolerance of the MCFC to SO_X, the natural gas entering the MCFC must be de-sulphurised to remove any traces of sulphur.

The additional particulate and SO_X abatement equipment will reduce the levels of other contaminants present in the EfW flue gas admitted to the MCFC. Like with other capture technologies uncertainty in relation to pre-treatment requirements and the lifespan of key components (the fuel cell) is reduced by testing with representative flue gas.

NO_X contamination in the flue gas is less of an issue for MCFCs than some capture technologies. The MCFCs can remove 70% or more of the NO_X in the flue gas.

18.1.2 Energy Use

The energy input to the MCFC comes from natural gas. The MCFC capture process results in a net surplus of electricity generation and, with limited modifications, can also be used to generate hydrogen. In the modelled scenario the hydrogen produced is recycled and provides energy to the MCFC. If the CO_2 is captured and stored, the electricity and hydrogen generated will be low carbon.

In the process, steam (or water) is added upstream of the MCFC module to allow reforming of the natural gas to take place in the fuel cell. In addition, a limited amount of steam is required for humidification of the natural gas entering the sulphur removal beds.

The MCFC generates excess steam beyond what is required by the facility. In the modelled scenario this steam is used to drive a steam turbine. The basis of the modelling conducted and performance of the MCFC came from a recent publication on the subject [32]. The excess steam available could alternatively be exported to provide a source of low carbon heat if there was a demand for thermal energy in the local area.

During normal operation the electrical and steam requirements of the system will be met using electricity and steam generated by the MCFC. Electrical connections to the host plant would be required for start-up of the MCFC. Depending on the complexity of connecting to the host plant, steam required for start-up could be provided by dedicated start-up boiler.

The lack of steam required for the capture process presents a benefit particularly when used on a cement plant as there is a limited amount of recoverable thermal energy available.

18.1.3 Current Demonstration Status

A 2.8 MWe MCFC power plant capturing CO_2 from the exhaust of a coal-fired power plant was supported by the US DOE in 2015. Subsequently in 2016, partnering with Exxon Mobil, another pilot at a coal and gas-fired power plant in Alabama, USA, was tested at 54 tpd CO_2 Capture.

In 2019 FuelCell Energy extended their relationship with Exxon Mobil with plans to install a demonstration unit at Exxon’s Rotterdam Refinery, data on the scale of the unit is not available. In the same year a FEED study was announced for an 85 tpd CO_2 Capture unit for Drax Power Station, UK.

FuelCell Energy have recently been awarded $6.8m by Canada’s Clean Resources Innovation Network which will be used to install their technology at the Scotford Upgrader site in Alberta, Canada [33].

There are currently no examples of MCFCs being used to capture carbon at the scale required for this scenario or being applied to a cement plant.

18.1.4 Technology Development

The use of methane (natural gas or biomethane) and the potential to generate low carbon electricity and hydrogen mean that the economics of capture using MCFC is fundamentally different to other capture technologies. This difference may provide opportunities in relation to the application of MCFCs. For example, where gas is available, and a supply of low carbon electricity or hydrogen is required in a certain area.

Another important difference to other capture technologies is that MCFCs are modular. Even in the future, if module sizes increase, it is anticipated that large installations will comprise of a bank of MCFC modules. This could be an advantage in relation to allowing a smaller facility to be constructed with the option for subsequent expansion if desired.

Key for the development of MCFC technology for use as a capture technology at a cement plant is the construction of a demonstration facility to provided baseline cost and performance information in this application.

Areas for technology development specific to MCFC technology include:

- Demonstration of reliable full system operation under representative conditions
- Optimising the structure of the MCFC stack
- Advancements in synthesising suitable electrode materials
- Advancements in catalysts used in the membrane electrode assembly
- Optimising flue gas pre-treatment systems to reliably protect the MCFC at an acceptable cost
- Identifying the most suitable industries to use MCFC based capture

Hazards

Key hazards in an MCFC facility are detailed below:

- High temperatures in and around the MCFC unit
- Pressurised equipment
- Electricity generated by the MCFC
- Alkali reagents used in the flue gas pre-treatment
- Fuel supply – natural gas
- Low temperatures associated with the cryogenic CO_2 conditioning equipment
- Methanol used in CO_2 separation
- Hydrogen gas
- The transportation and storage of CO_2

The first four of these hazards will already be present in some form at the host cement facility.

Maintenance

Upstream of the MCFC modules treatment of the flue gas is required using alkali reagents and bag filters. Operators at the host cement facility will be familiar with this kind of equipment. However, systematic, and effective operation and maintenance of the units will be required as any performance issues in this part of the process have the potential to damage the MCFC modules.

The MCFC modules at the core of the capture process have no moving parts, which is an advantage in relation to maintenance. However, MCFC modules will degrade and have a limited lifespan. Degradation rates will depend on the MCFC module used and the effectiveness of upstream contaminant removal.

Downstream of the MCFCs the cryogenic CO_2 upgrading system contains an array of pumps, compressors, and heat exchangers. While the maintenance requirements of this equipment are generally well understood, understanding the details of the equipment configuration with respect to redundancy and availability will be important in relation to understanding maintenance requirements.

The MCFC system also contains catalytic reactors, including the oxidiser prior to the MCFC, for oxidising CO and H_2, and the shift reactor after the MCFC for converting CO and H_2O to CO_2 and H_2. Periodic replacement of catalysts in these reactors will be required.

18.2 Cost Summary

Table 84 and Table 85 contain a summary of the capital and annual operational costs for the carbon capture plant.

Table 84. MCFC – Cement Capital cost

Item	Cost
EPC Costs	
Flue Gas Pre-Treatment	£22.9m
Capture Technology	£34.3m
Conditioning	£7.3m
Compression	£13.2m
Auxiliary Systems	£78.3m
Civil works	£32.4m
Total EPC	**£188.4m**
Project Development Costs	
Land Requirements	£0.3m
Utility & Infrastructure Connections	£1.9m
Consultancy	£1.9m
Planning & Other Regulatory	£3.8m
Developer’s Costs	£13.2m
Start-Up & Commissioning	£9.4m
Total Project Development	**£30.4m**
Total Capital Cost	
Total Capital Cost	£218.8m
Contingency	10%
Grand Total CAPEX	**£240.7m**

Table 85. MCFC – Cement Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.9m
Administration	£3.6m
Maintenance	£6.0m
Total fixed OPEX	**£10.5m**
Variable Costs	
Natural gas	£37.5m
Electricity	-£35.4m
Steam supply	£0.0m
MCFC replacement	£3.4m
Other chemicals and consumables	£0.0m
Wastes	£0.2m
Plant auxiliary	£0.2m
Total variable OPEX	**£6.1m**
Total Operating Cost	
Total Operating Cost	£16.6m
Contingency	10%
Grand Total OPEX	**£18.3m**

18.3 Key Outputs

Table 86 contains a summary of the values relating to the LCOC. The MCFC is being used as a capture technology, but it also consumes natural gas and generates electricity. Therefore, the LCOC will be influenced by the economics of power generation from gas in a way that other capture technologies are not.

Table 86. MCFC – Cement Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	1.0 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	24.9 Mt	Based on annual CO_2 capture and design life. The mass of CO_2 captured in the MCFC EfW scenario is higher than the other EfW scenarios as additional CO_2 from the use of natural gas is captured.
Discounted lifetime CO_2 captured	9.3 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£240.7m	
Total annual OPEX	£18.3m	
Lifetime cost	£697.0m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£389.4m	Adjusted lifetime cost value based on discount rate.
LCOC	**£42/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. In the MCFC scenarios more CO_2 is captured due to the CO_2 from the natural gas used also being captured in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 44.

Figure 44. Molten Carbonate Fuel Cell LCOC

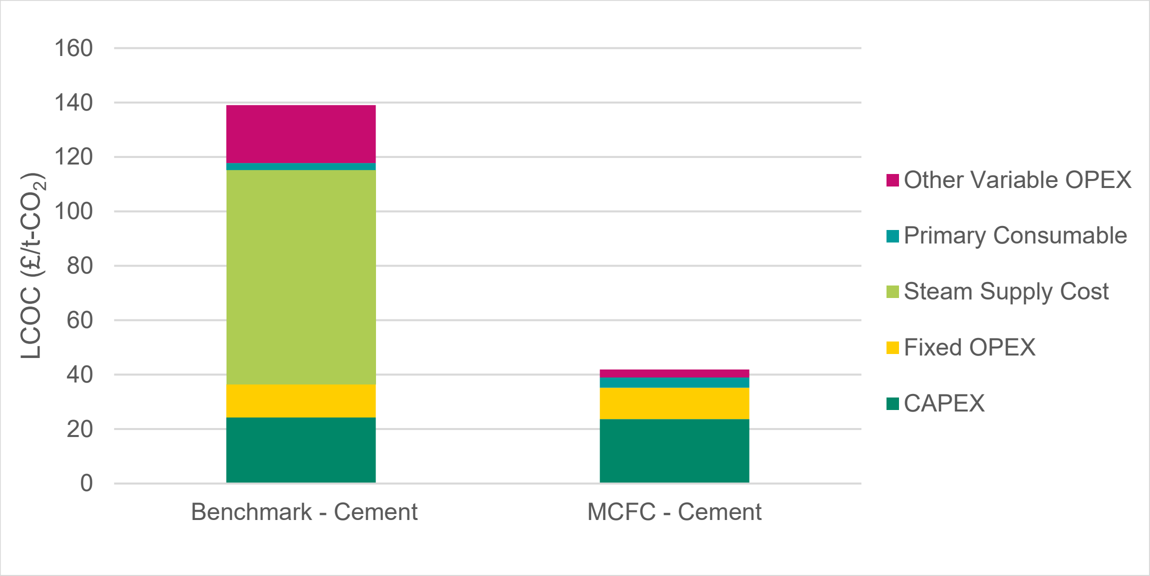


Figure 44 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is c.95% for both scenarios.
3. Both scenarios produce pipeline grade CO_2. In the MCFC scenario, it is produced in liquid phase.
4. The MCFC also consumes natural gas and generates electricity. Therefore, LCOC values will be influenced by the economics of power generation from gas in a way that other capture technologies are not. The 'Other variable OPEX' segment in the MCFC scenario include both a natural gas cost and a negative operating cost resulting from electricity export.
5. More CO_2 is captured in the MCFC cases, relative to the other scenarios in the EfW and cement sectors, due to capture of the CO_2 from the natural gas used in addition to the CO_2 captured from the cement process, and hence LCOC is reduced commensurately.
6. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

A reduction in LCOC is indicated relative to the benchmark scenario. The MCFC requires more onerous control of flue gas contaminants than other technologies included in this report. Therefore, the results obtained are more reliant on the cost and performance of the flue gas pre-treatment equipment than in other scenarios. Validation of cost and performance data for suitable flue gas pre-treatment systems will be an important part of developing MCFCs for use in industrial capture applications.

Table 87 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 87. MCFC – Cement Impact on product cost

Item	Value	Comment
Product produced	Decarbonised clinker	
Lifetime mass of clinker produced	25 Mt	
Lifetime CO_2 captured	24.9 Mt	
LCOC	£42/t	From calculations above
Lifetime CO_2 residual emissions	1.0 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£14.0m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64.5/t-clinker	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£106/t-clinker +£42/t-clinker +65% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£78/t-clinker +£13/t-clinker +21% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£119/t-clinker +£55/t-clinker +85% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£332/t-clinker +£267/t-clinker +414% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

18.4 Modelling Assumptions

Table 88 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 88. MCFC – Cement Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Capture plant availability	85%	Medium	Medium	High	The limited scale of pilot plants and the lack of operation on cement plant flue gas creates uncertainty in relation to operation with high availability at the modelled scale.
Input flue gas composition	See Appendix B	High	Medium	Medium	The MCFC requires lower levels of contaminants than other capture technologies and performance on treated cement plant flue gas remains to be demonstrated.
Overall capital cost	See Table 84	Medium	Medium	High	The limited number of examples of this technology creates unavoidable uncertainty in relation to capital cost. Risk magnitude could be controlled by adding modules to an initially smaller project.
Maintenance	See Table 85	Medium	Medium	High	The limited number of examples of this technology creates unavoidable uncertainty in relation to maintenance cost.
Electricity generation	See Table 85	Medium	Medium	High	The generation of low carbon electricity could be an advantage at many sites, provided that there is a demand for the power, or it can be exported. If the MCFC installation has a lower overall efficiency than predicted, then less power will be available to export.

Steam consumption	See Table 85	High	Low	Low	Steam consumption is relatively low at a MCFC capture plant, and the MCFC process can generate excess steam through waste heat recovery. The scenario assumes no steam will come from an external source.
Steam price	See Section 9.1.2	Medium	Low	Low	Steam consumption is relatively low at a MCFC capture plant, and the MCFC process can generate excess steam through waste heat recovery. The scenario assumes no steam will come from an external source
Natural gas consumption	See Table 85	High	Medium	Medium	If the MCFC installation has a lower degree of heat integration than predicted, then natural gas consumption would increase.
Primary consumables (MCFC module)	See Table 85	Low	Medium	Very High	When using natural gas and air (rather than flue gas) a lifespan in the order of seven years could be expected from a MCFC stack. However, the lifespan of the MCFC remains to be proven in representative conditions. Any performance issues in upstream flue gas equipment have the potential to reduce cell life.
Input gas pre-treatment	See Table 83	Medium	Medium	High	The lower contaminant levels required in the input gas for the MCFC can be achieved by installing additional flue gas pre-treatment equipment. There will be challenges associated with reliably protecting the MCFC stack against damage from contaminants without incurring excessive equipment costs.
CO_2 conditioning	See Table 83	Medium	Low	Low	The more extensive input gas pre-treatment required by the MCFC will be an advantage in relation to post capture CO_2 conditioning. Hydrogen and water are removed from the CO_2 using well-established process technologies. However, if gas phase CO_2 is required, rather than liquid phase, then additional equipment and thermal energy will be required.

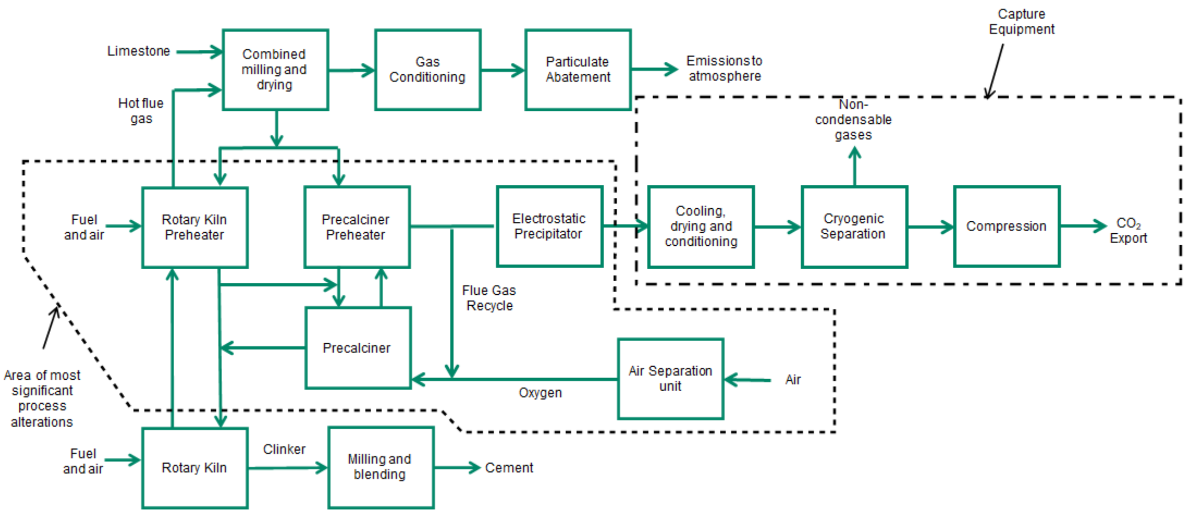
Overall, there is a *high* level of uncertainty associated with the modelling of this scenario. MCFCs have potential advantages in relation to integration with the host plant, modular construction, and the production of low carbon electricity. Testing on representative flue gases is required to validate cost and performance assumptions.

19. Partial Oxyfuel Combustion – Cement

19.1 Description of Scenario

This scenario involves retrofitting an existing 1 Mtpa clinker, cement plant with a partial oxyfuel combustion system. Figure 45 shows a block flow diagram of the process.

Figure 45. Block Diagram – Cement plant with partial oxyfuel combustion



Oxyfuel technology is a process alteration that aids capture, rather than a standalone capture technology. When combustion air is substituted for oxygen, in all or part of the process, the concentration of CO_2 in the resulting flue gas increases due to reduced levels of nitrogen. A higher concentration of CO_2 in the flue gas is an advantage in relation to capturing CO_2 from the flue gas. However, additional CO_2 separation equipment is still required to produce a pure stream of CO_2. In this scenario, a cryogenic system is used but other options are available.

In an oxyfuel system the benefits of a higher CO_2 concentration in the flue gas need to be balanced against the cost of modifying the plant and the energy cost associated with generating the oxygen required. Compared to a typical solvent based capture system, an oxyfuel plant will use more electrical energy and less thermal energy. This could be an advantage at some sites depending on the energy supply options available.

The use of oxyfuel technology requires review and modification of equipment at various stages of the cement manufacture process, as detailed in the Configuration Summary table below. This makes the interface with the existing plant more complex than for post combustion capture technologies. Hence, no ‘Interface with host facility’ line is shown in Figure 45. In addition, this introduces site specific considerations in relation to the application of oxyfuel technology; some plants will be more suited to it than others.

This scenario is a partial oxyfuel system. This means that oxyfuel combustion, or oxyfuel combustion gases are present in the precalciner and the associated preheater but not in the rotary kiln. This allows the oxyfuel system to be implemented with less extensive plant modifications, so is considered more appropriate for a retrofit application. Full oxyfuel combustion would allow a higher CO_2 capture level but would require significant modifications to the extent that it is only likely to be considered for a new cement plant. Higher capture levels could also be achieved with partial oxyfuel if an additional capture technology was applied to the emissions from the rotary kiln.

A summary of technical information for the base process and carbon capture plant is presented in Table 89.

Table 89. Partial Oxyfuel Combustion - Configuration summary

Item	Description
Base Process Plant	**Existing cement manufacturing site**
Plant capacity	1 Mtpa clinker (approximately 10% of UK capacity)
Fuels used	Coal c.40% of thermal energy input Alternative waste fuels c.60% of thermal energy input Fuel mix is based on assumed future usage; current mix is typically 50% coal.
Flue gas output (prior to oxyfuel modification)	409 tph 18 mol% CO_2
Process modifications and CO_2 conditioning	**Partial oxyfuel combustion**
Flue gas to capture plant (with oxyfuel modification)	84 tph 77 mol% CO_2
Oxygen generation distribution and use	Air separation unit (ASU) to produce oxygen Oxygen distribution system Oxyfuel burners
Host plant modifications	New preheater for oxyfuel operation – the precalciner preheater New conventional preheater – the rotary kiln preheater New precalciner including flue gas recycle to control flame temperature in oxyfuel burners Changes to feedstock drying, only combustion gases from rotary kiln preheater are used Heat integration system Plant sealing to reduce air intrusion Upgrades to connecting pipes, ducts, auxiliary services and utilities Review of potential impact on all other plant equipment and systems.
Compression	Single compression train
Conditioning	Deoxygenation NO_X removal using reagent Desiccant drying Cryogenic CO_2 separation unit
CO_2 capture level	c.60% of CO_2 emissions from flue gas during normal operation Greenhouse gas emissions from energy imports are not included
Operational hours	7,446 hours/year (8,760 hours * 85%)
CO_2 export pressure	27.5 barg for gathering network
Mass of CO_2 captured	65 tph (1549 tpd)
Electricity supply	16 MW imported from external source

19.1.1 Oxyfuel Cement Manufacture

When oxyfuel technology is applied to the cement manufacturing process it will impact the process in several ways. The extent and range of the impacts will vary depending on how the oxyfuel technology is applied.

There are other potential process benefits to supplying cement plant combustion apparatus with oxygen, aside from aiding capture of CO_2. In the USA, trials have been conducted using oxygen enrichment primarily to allow plant capacity to be increased. Similarly, in Germany oxygen enrichment has been trialled as a tool to allow increased use of low calorific value and secondary fuels [42]. In this analysis, other potential benefits to the cement manufacture process have not been considered in relation to the LCOC.

While there are potential process benefits of using oxyfuel technology in cement manufacture, there are also additional costs and uncertainties. In addition to cost and performance uncertainties, the use of oxyfuel technology has the potential to impact on product quality. This is due to altered process conditions and increased CO_2 levels when the calcination reaction is taking place. Any potential impacts on product quality would need to be investigated for any development proposing to use oxyfuel technology. To date, operators have generally considered the costs and risks to outweigh the benefits, and hence oxyfuel technology is rare in the global cement industry. In addition to the requirement for new equipment, such as an air separation unit, modifications can be required across the plant, and these introduce new process risks and uncertainty.

19.1.2 Energy Use

The main energy inputs for this scenario are the electrical energy required for the ASU and the cryogenic CO_2 separation unit. Both units are electrically operated. The magnitude of the additional electricity consumption is such that the requirements of the plant may exceed the capacity of the existing connection to the electricity grid. In this case, there may be additional costs associated with upgrading existing utility connections and infrastructure.

The use of oxygen, rather than air, as an oxidising agent may allow fuel savings to be made as there is no need to heat the nitrogen present in the air during the combustion process. Therefore, more of the energy released by combustion of fuel is available for heating the process material. However, the production of oxygen is an energy intensive process and will result in the indirect release of CO_2, with the mass of CO_2 released being dependant on the energy source used to generate the oxygen. To obtain a true picture of CO_2 savings from oxyfuel technology, the CO_2 emissions associated with the energy required to generate the oxygen should also be considered.

19.1.3 Current Demonstration Status

Oxyfuel technology has potential advantages over the benchmark case, but it is at an earlier stage of development with respect to use of oxygen firing in cement plants (production of oxygen in an ASU is an established technology). Some relevant experience of oxyfuel technology has been gained in the power sector. In addition, various trials have been conducted with oxygen enrichment at cement plants in the USA and Germany.

Cement plants in Colleferro, Italy and Retznei, Austria have been identified as sites for oxyfuel technology demonstration projects to be constructed as part of the AC^{2}OCem project. This announcement was made by the European Cement Research Academy (ECRA) in 2018, but it is unclear when the plants will begin operation. The catch4climate project also has plans to build and operate an oxyfuel test facility at a semi-industrial scale at the Mergelstetten cement plant in Germany.

Desk based research and laboratory experiments have been conducted by various institutions relating to the use of oxyfuel technology in the cement industry. This work continues to improve understanding of how projects could be implemented and associated technical challenges could be overcome. However, there are currently no known projects demonstrating either partial or full oxyfuel combustion at cement plants with a scale comparable to this scenario.

19.1.4 Technology Development

There are different configurations of oxyfuel technology that can be applied to cement manufacturing. Research is ongoing in relation to improving the configurations and understanding the relative merits of the different options available. Key for the development of using oxyfuel technology to aid capture is the construction of a demonstration facility to gain practical experience and provide baseline cost and performance information.

As well as aiding capture, oxyfuel technology has been proposed at cement plants for alternative purposes. These include increasing production capacity or allowing lower calorific value fuels to be used. The merits of these different potential benefits should be assessed in conjunction with studies into using the technology to aid carbon capture.

Hazards

Hazards associated with solvent and solvent degradation products are eliminated in this scenario as there are no chemical reactions involved in the capture process.

The process requires an ASU to generate the required oxygen and a cryogenic process to upgrade the CO_2 rich flue gas produced. This introduces hazards associated with processing of low temperature fluids, pressurised systems and oxygen gas. Oxygen in higher concentrations significantly lowers the flammability limit of combustible materials.

As with the benchmark scenarios, there are hazards associated with the transportation and storage of CO_2.

Maintenance

Both the air separation unit and the cryogenic CO_2 upgrading system contain an array of pumps, compressors, and heat exchangers. While the maintenance requirements of this equipment are generally well understood, understanding the details of the capture plant configuration with respect to redundancy and availability will be important in relation to understanding maintenance requirements.

Using oxygen and recycled flue gas in the combustion equipment, rather than air, will change the process conditions throughout much of the cement plant. Changes could include temperature differences, variations to gas flow rates and different physical and chemical properties of material streams. These changes will impact maintenance requirements across the cement manufacturing process. Research has been conducted on the impact of oxyfuel technology on refractory durability as it will be impacted using oxyfuel technology.

19.2 Cost Summary

Table 90 and Table 91 contain a summary of the capital and annual operational costs for this scenario.

Table 90. Partial Oxyfuel Combustion – capital cost

Item	Cost
EPC Costs	
Air Separation Unit	£19.8m
Partial Oxyfuel Technology and Process Modifications	£40.9m
Compression, cryogenic separation and conditioning	£13.7m
Auxiliary Systems	£10.7m
Civil works (included in Process Modifications cost)	£0.0m
Total EPC	£85.0m
Project Development Costs	
Land Requirements	£0.2m
Utility & Infrastructure Connections	£0.9m
Consultancy	£0.9m
Planning & Other Regulatory	£1.7m
Developer's Costs	£6.0m
Start-Up & Commissioning	£4.3m
Total Project Development	£13.8m
Total Capital Cost	
Total Capital Cost	£98.8m
Contingency	10%
Grand Total CAPEX	£108.6m

Table 91. Partial Oxyfuel Combustion - Average annual operational cost

Item	Cost
Fixed Costs	
Labour	£0.7m
Administration	£1.6m
Maintenance	£2.7m
Total fixed OPEX	£5.1m
Variable Costs	
Electricity	£15.0m
Steam supply	£0.0m
Other chemicals and consumables	£0.3m
Wastes	£0.1m
Plant auxiliary	£0.2m
Total variable OPEX	£15.6m
Total Operating Cost	
Total Operating Cost	£20.7m
Contingency	10%
Grand Total OPEX	£22.8m

19.3 Key Outputs

Table 92 contains a summary of the values relating to the LCOC.

Table 92. Partial Oxyfuel Combustion – Levelised cost of CO_2 capture

Item	Value	Comment
CO_2 captured	0.5 Mt/yr	Function of hourly capture rate and plant availability.
Lifetime CO_2 captured	12.0 Mt	Based on annual CO_2 capture and design life.
Discounted lifetime CO_2 captured	4.5 Mt	The number of units of product generated is typically discounted in levelised cost calculations. See Methodology in Appendix B for details of the equations used.
Total CAPEX	£108.6m	
Total annual OPEX	£22.8m	
Lifetime cost	£678.3m	Total CAPEX plus annual OPEX multiplied by design life.
Discounted lifetime cost	£313.9m	Adjusted lifetime cost value based on discount rate.
LCOC	**£70/t**	Discounted lifetime cost divided by discounted lifetime CO_2 captured. LCOC does not include transport and storage of CO_2 or the cost of residual CO_2 emissions.

A chart of the LCOC for this scenario compared against the benchmark is provided in Figure 46.

Figure 46. Partial oxyfuel combustion LCOC

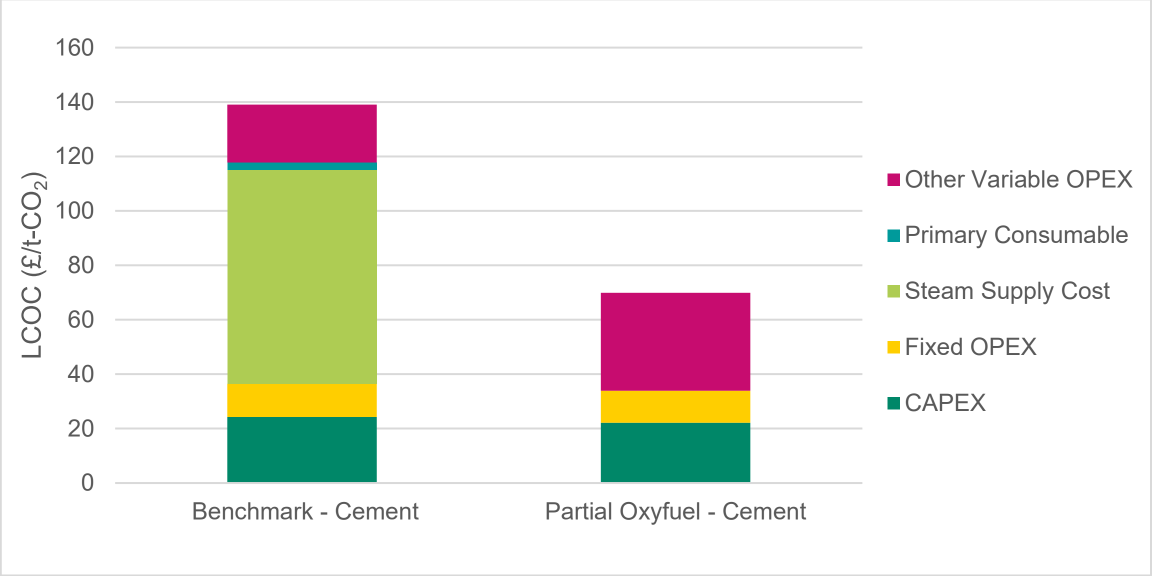


Figure 46 Footnotes

1. LCOC values relate to capture only. Costs for residual CO_2 emissions and CO_2 transport and storage are not included.
2. Capture level is 95% for the benchmark scenario and 60% for partial oxyfuel. With the assumed CO_2 emission prices, residual emission costs and the impact on product cost, will be higher for the lower capture levels for this scenario.
3. Partial oxyfuel combustion is a process alteration that aids capture, rather than standalone capture technology. Impacts on the cement manufacturing process may not be reflected in the LCOC values.
4. LCOC is only one aspect of technology performance. The results must be considered in conjunction with the information provided on demonstration status, opportunities, challenges, and assumptions.

The capture level in this scenario is lower than the benchmark and this may be an issue in a net zero business environment. Capture level could be improved by using an additional capture technology, such as a solvent based system, to capture CO_2 from the combustion flue gases. Waste heat from the clinker manufacture process could contribute to the energy requirements of the additional capture technology.

Table 93 contains a summary of values relating to the impact of adding carbon capture on product cost.

Table 93. Partial Oxyfuel Combustion – Impact on product cost

Item	Value	Comment
Product produced	Decarbonised clinker	
Lifetime mass of clinker produced	25 Mt	
Lifetime CO_2 captured	12.0 Mt	
LCOC	£70/t	From calculations above
Lifetime CO_2 residual emissions	8.4 Mt	
Average annual cost of residual CO_2 emissions to atmosphere	£116.2m	Based on the assumed CO_2 emissions price and capture level.
Product market price	£64.5/t-clinker	Price includes no cost to the host plant for emission of CO_2 to the atmosphere. This is broadly in line with current emissions trading scheme requirements.
Product cost with impact of capture only	£98/t-clinker +£34/t-clinker +52% of market price	Product market price plus the cost associated with capture of the CO_2.
Product cost with impact of residual CO_2 emissions only	£175/t-clinker +£110/t-clinker +171% of market price	Product market price plus the cost associated with emission of uncaptured CO_2 to the atmosphere.
Product cost with impact of capture and residual CO_2 emissions	£208/t-clinker +£144/t-clinker +223% of market price	Product market price plus costs associated with CO_2 capture and emission of uncaptured CO_2. If a cost were to be assumed for transport and storage, then the impact on product cost would increase.
Unabated product cost	£332/t-clinker +£267/t-clinker +414% of market price	Product market price with no capture, plus the assumed cost for emission of CO_2.

With the assumed CO_2 emission prices, the impact on product cost is higher in technology scenarios with lower capture levels. This is due to the relatively high cost of emitting residual CO_2 to the atmosphere. If CO_2 emission prices were lower, then a solution offering an attractive LCOC, but with a lower capture level, may give a lower cost of product.

19.4 Modelling Assumptions

Table 94 provides commentary on the modelling assumptions and uncertainties that specifically relate to this scenario. Details of modelling assumptions that relate to all scenarios are provided in the Methodology report in Appendix B. In addition, this section should be read in conjunction with an understanding of general opportunities and barriers for carbon capture, as detailed in the *Review of Next Generation Technologies* conducted as part of this assignment.

Table 94. Partial Oxyfuel Combustion – Cement Summary of modelling assumptions

Parameter	Value	Data Quality	Model Impact	Uncertainty	Comment
Plant availability	85%	Medium	High	Very High	The technology is yet to demonstrate operation in a commercial setting due to its stage of development. The impact of downtime is increased because it will impact the cement manufacturing plant and not just the capture process.
Overall capital cost	See Table 90	Medium	Medium	High	The demonstration status of this technology creates unavoidable uncertainty in relation to capital cost.
Maintenance	See Table 91	Medium	Medium	High	The demonstration status of this technology creates unavoidable uncertainty in relation to maintenance cost. Long term impacts on existing cement plant equipment are uncertain.
Electricity consumption	See Table 91	Medium	Medium	High	Electricity, used to operate the ASU and cryogenic equipment, is the single largest operating cost for the system. Changes in price or consumption of electricity may impact LCOC.
Steam consumption	See Table 91	NA	NA	NA	No steam is required at the plant.
Steam price	See Section 16.1.2	NA	NA	NA	No steam is required at the plant.
CO_2 conditioning	See Table 89	Medium	Medium	High	The cryogenic CO_2 conditioning process required to remove non-condensable gases from the CO_2 produced is more onerous than the conditioning systems for some other capture technologies. Process operations to control oxygen and NO_X levels have also been included.

Overall, there is a *very high* level of uncertainty associated with the modelling of this scenario. As a process alteration, oxyfuel technology has potential advantages in relation to capital costs, energy costs and some performance aspects for the base process plant. However, operation of the technology remains to be demonstrated at scale and any availability issues would impact cement production.

20. Abbreviations

ASU	Air Separation Unit
BAT	Best Available Technique
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CC	Carbon Capture
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Usage and Storage
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DCC	Direct Contact Cooler
DSR	Direct Separation Reactor
EfW	Energy from Waste
EPC	Engineering, Procurement and Construction
EU	European Union
FEED	Front End Engineering Design
HPC	Hot Potassium Carbonate
HRSG	Heat Recovery Steam Generator
IEAGHG	International Energy Agency Greenhouse Gas R&D Programme
LCOC	Levelised cost of capture
LEILAC	Low Emissions Intensity Lime and Cement
LNG	Liquefied Natural Gas
MCFC	Molten Carbonate Fuel Cell
MEA	Monoethanolamine
MOF	Metal Organic Framework
MSW	Municipal Solid Waste
MWe	Megawatts electrical
MWh	Megawatt hour
MWth	Megawatts thermal
N/A	Not Applicable
OPEX	Operating Expenditure

ppmv	parts per million volume
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
TCM	Technology Centre Mongstad
TEG	Triethylene glycol
TERC	Translational Energy Research Centre
tpa	tonnes per annum
tpd	tonnes per day
tph	tonnes per hour
UKCCSRC	UK Carbon Capture and Storage Research Council
WP	Work Package

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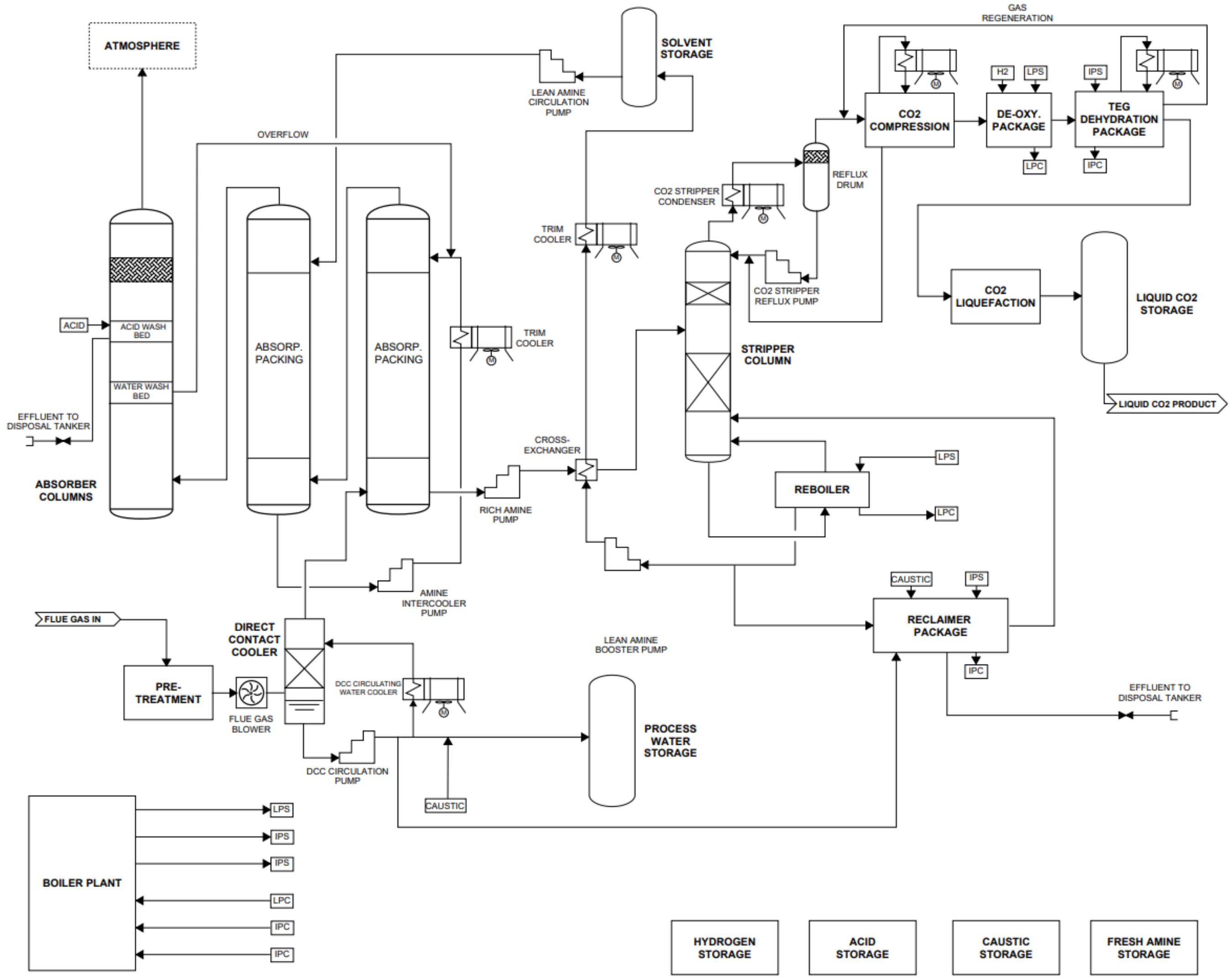
Appendix A - Process Diagrams

This section contains more detailed diagrams of some of the capture processes discussed in this report. The diagrams were all either produced by AECOM, provided by a technology provider or obtained from publicly available online sources.

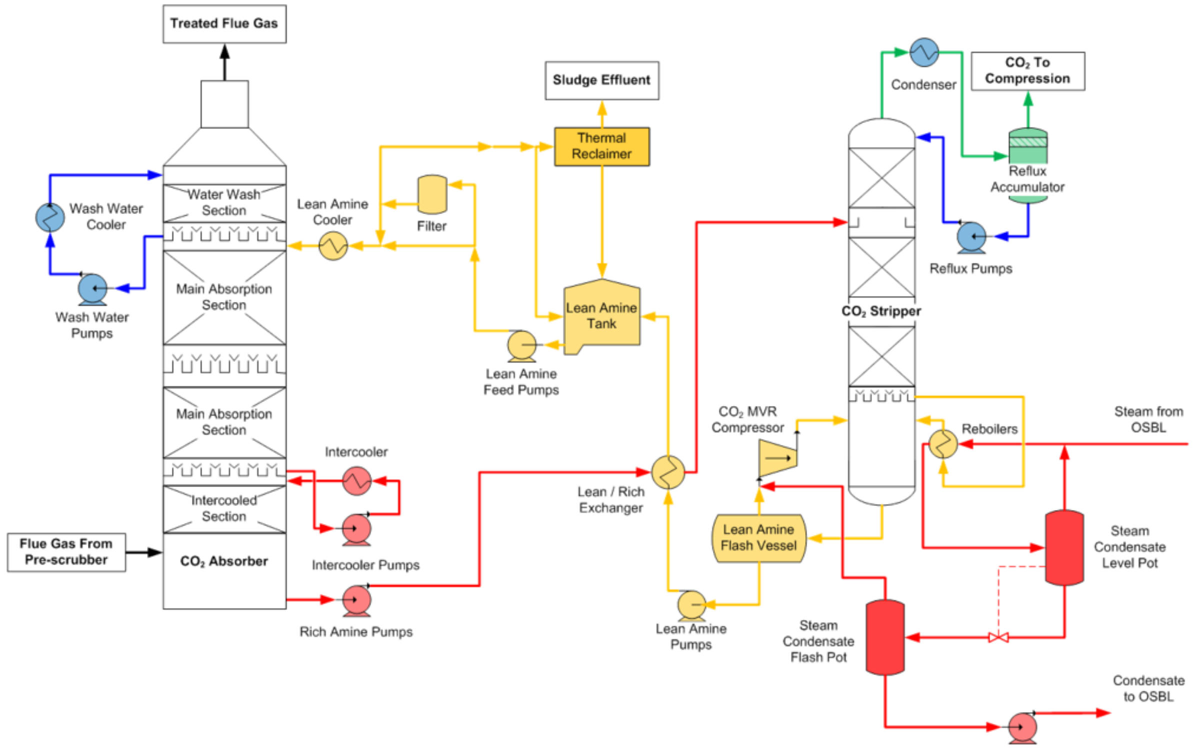
A.1 Benchmarks

The following process flow diagram of amine-based capture on a gas-fired power plant was produced by AECOM as part of the case study of a mobile demonstration plant carried out in WP4 of this study.



A.2 Advanced Amine

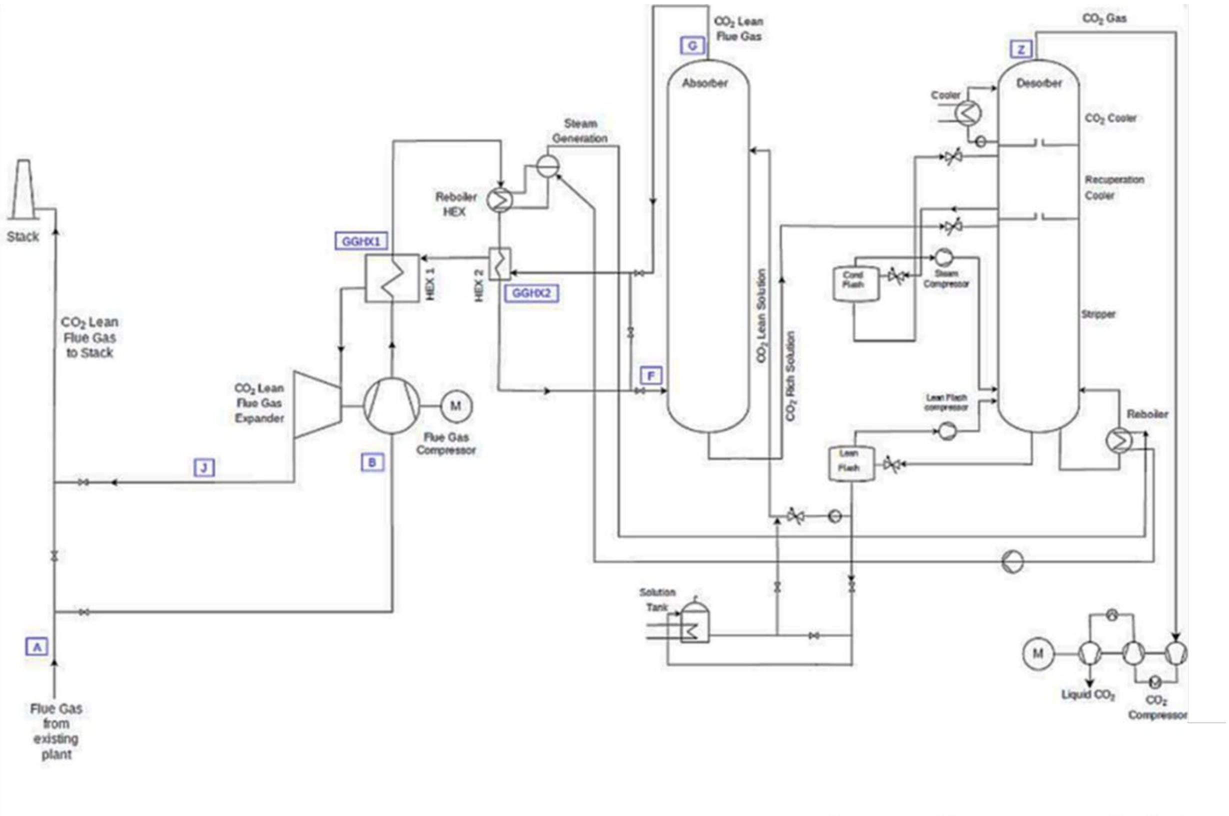
The following diagram of an advanced amine-based capture process was provided by Shell.



CANSOLV CO_2 Capture System simplified PFD

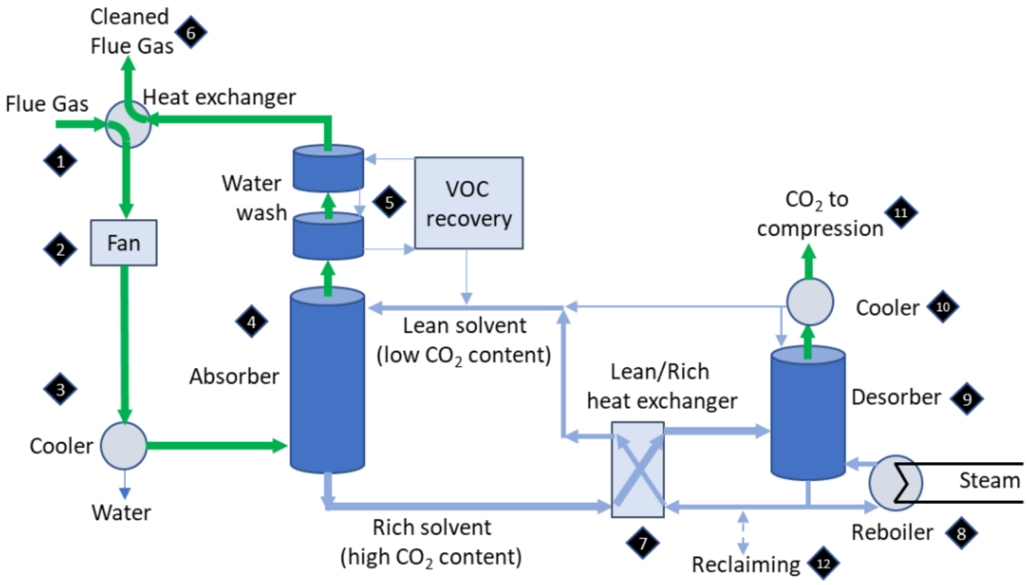
A.3 Hot Potassium Carbonate

The following diagram of a post combustion capture process using a hot potassium carbonate (HPC) solvent was provided by CO2 Capsol.



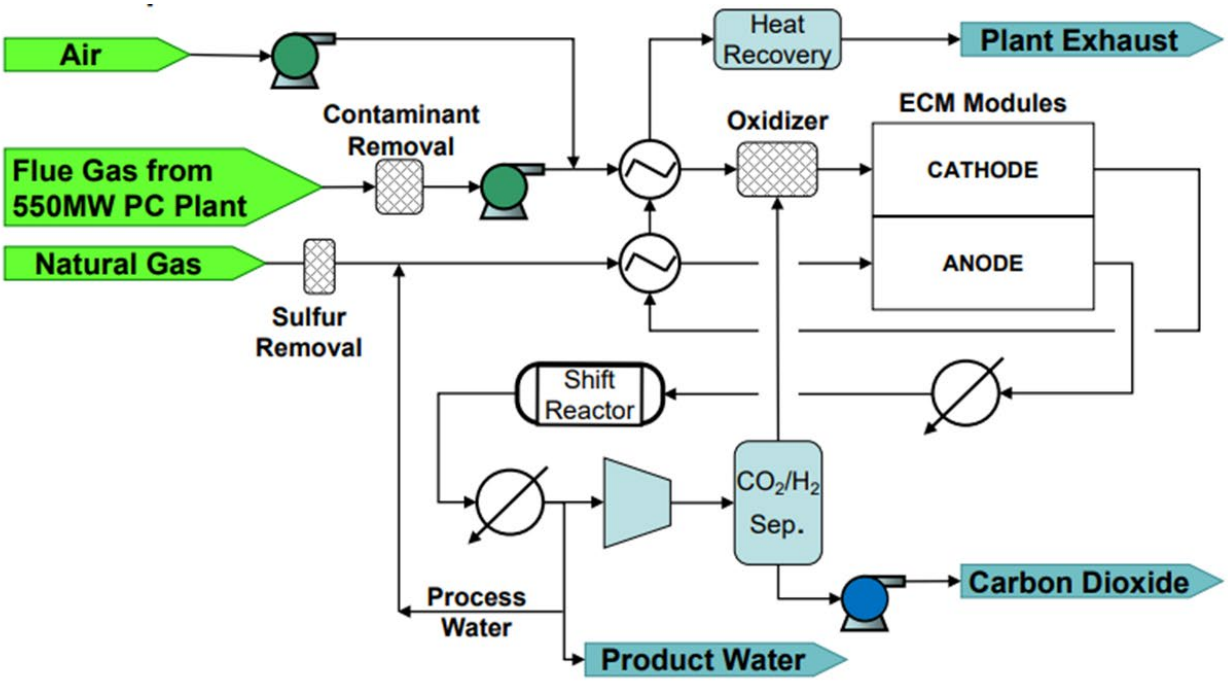
A.4 Non-Amine Solvent

The following diagram of a post combustion capture process using a non-amine solvent was provided by C-Capture.



A.5 Molten Carbonate Fuel Cell

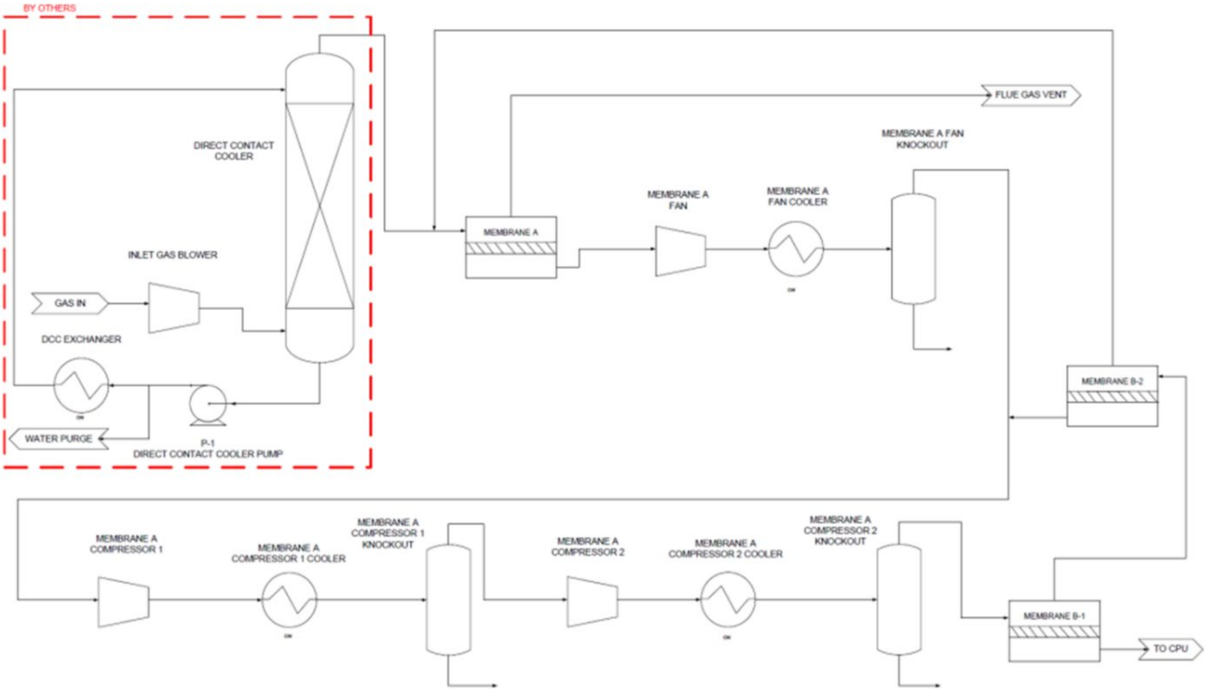
The following diagram of FuelCell Energy's proposed process for post combustion capture using a fuel cell was obtained from a FuelCell Energy presentation published on the National Energy Technology Laboratory's website [43].



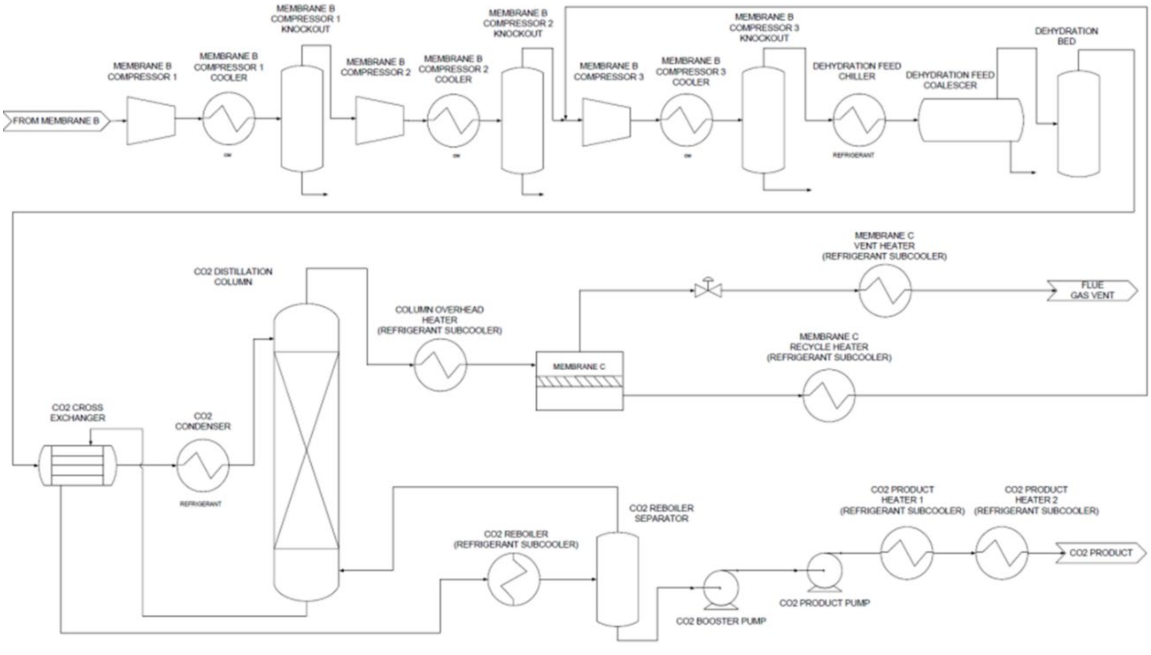
A.6 Polymeric Membrane

The following process flow diagrams of a post combustion, membrane-based capture process were obtained from the publicly available initial engineering design report by EPRI based on MTR’s technology [44]. This process design is based on capture on flue gas from a coal-fired power station.

CO_2 Capture Unit Process Flow Diagram

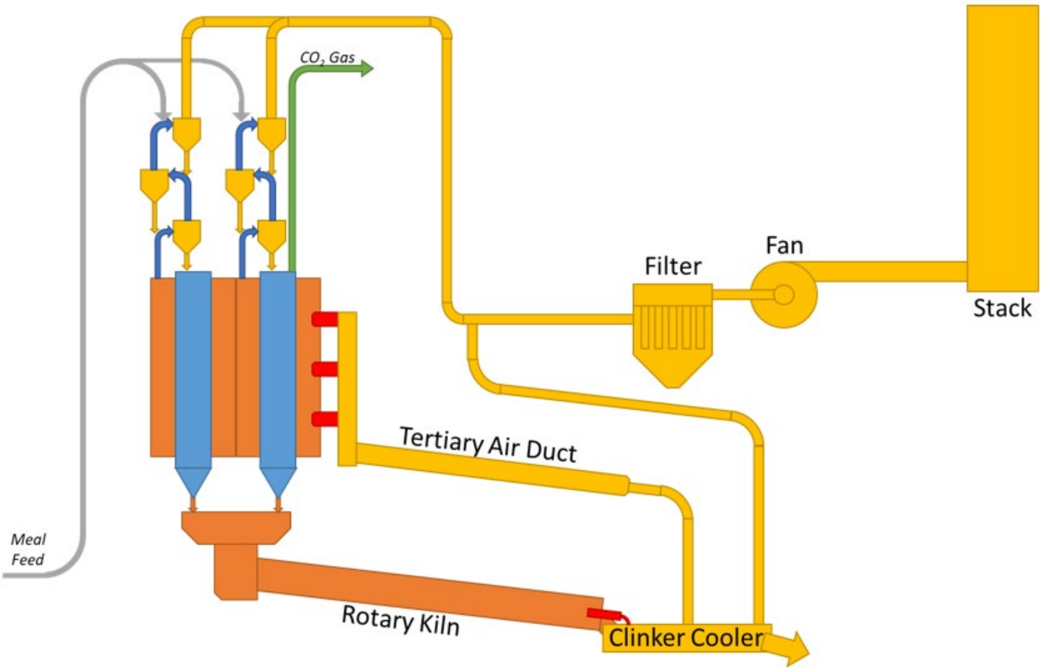


CO_2 Purification Unit Process Flow Diagram



A.7 LEILAC Technology

The following diagram of the Low Emissions Intensity Lime and Cement (LEILAC) capture process was provided by Calix.



Appendix B – Technoeconomic Assessment Methodology

Annex 1 - Technology Review

Annex 2 – Mobile De-Risking Plant